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No. 14-___

IN THE

Supreme Court of the United States

NATIONAL MINING ASSOCIATION, PETITIONER

v.

ENVIRONMENTAL PROTECTION AGENCY, RESPONDENT

ON PETITION FOR WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

PETITION FOR A WRIT OF CERTIORARI
VOLUME 2 of 4

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July 14, 2014

WILSON-EPES PRINTING CO., INC. – (202) 789-0096 – WASHINGTON, D C 20002

Table 4--Emission Limitations for Liquid Oil-Fired EGUs

Subcategory	Filterable particulate matter	Hydrogen chloride	Hydrogen fluoride
Existing--Liquid oil--continental	3.0E-2 lb/MMBtu (3.0E-1 lb/MWh)	2.0E-3 lb/MMBtu (1.0E-2 lb/MWh)	4.0E-4 lb/MMBtu. (4.0E-3 lb/MWh).
Existing--Liquid oil--non-continental	3.0E-2 lb/MMBtu (3.0E-1 lb/MWh)	2.0E-4 lb/MMBtu (2.0E-3 lb/MWh)	6.0E-5 lb/MMBtu. (5.0E-4 lb/MWh).
New--Liquid oil--continental	7.0E-2 lb/MWh	4.0E-4 lb/MWh	4.0E-4 lb/MWh.
New--Liquid oil--non-continental	2.0E-1 lb/MWh	2.0E-3 lb/MWh	5.0E-4 lb/MWh.

We are also finalizing alternate equivalent emission standards (for certain subcategories) to the final surrogate standards in three areas: SO_2 (for HCl), individual non-mercury metals and total non-mercury metals (for filterable PM) from coal- and solid oil-derived fuel-fired EGUs, and individual and total metals (for filterable PM) from oil-fired EGUs. The final alternate emission limitations are provided in Tables 5 and 6 of this preamble.

Table 5--Alternate Emission Limitations for Existing Coal- and Oil-Fired EGUs

Subcategory/ Pollutant	Coal-fired EGUs	IGCC	Liquid oil, continental	Liquid oil, non-continental	Solid oil-derived
SO[2]	2.0E-1 lb/MMBtu (1.5E0 lb/MWh)	NA	NA	NA	3.0E-1 lb/MMBtu. (2.0E0 lb/MWh)
Total non-mercury metals	5.0E-5 lb/MMBtu (5.0E-1 lb/GWh)	6.0E-5 lb/MMBtu (5.0E-1 lb/GWh)	8.0E-4 lb/MMBtu (8.0E-3 lb/MWh) fna	6.0E-4 lb/MMBtu (7.0E-3 lb.MWh) fna	4.0E-5 lb/MMBtu. (6.0E-1 lb/GWh).
Antimony, Sb	8.0E-1 lb/TBtu (8.0E-3 lb/GWh)	1.4E0 lb/TBtu (2.0E-2 lb/GWh)	1.3E+1 lb/TBtu (2.0E-1 lb/GWh)	2.2E0 lb/TBtu (2.0E-2 lb/GWh)	8.0E-1 lb/TBtu. (8.0E-3 lb/GWh).
Arsenic, As	1.1E0 lb/TBtu (2.0E-2 lb/GWh)	1.5E0 lb/TBtu (2.0E-2 lb/GWh)	2.8E0 lb/TBtu (3.0E-2 lb/GWh)	4.3E0 lb/TBtu (8.0E-2 lb/GWh)	3.0E-1 lb/TBtu. (5.0E-3 lb/GWh).
Beryllium, Be	2.0E-1 lb/TBtu (2.0E-3 lb/GWh)	1.0E-1 lb/TBtu (1.0E-3 lb/GWh)	2.0E-1 lb/TBtu (2.0E-3 lb/GWh)	6.0E-1 lb/TBtu (3.0E-3 lb/GWh)	6.0E-2 lb/TBtu. (6.0E-4 lb/GWh).
Cadmium, Cd	3.0E-1 lb/TBtu (3.0E-3 lb/GWh)	1.5E-1 lb/TBtu (2.0E-3 lb/GWh)	3.0E-1 lb/TBtu 2.0E-3 lb/GWh)	3.0E-1 lb/TBtu (3.0E-3 lb/GWh)	3.0E-1 lb/TBtu. (4.0E-3 lb/GWh).

Table 5--Alternate Emission Limitations for Existing Coal- and Oil-Fired EGUs

Subcategory/ Pollutant	Coal-fired EGUs	IGCC	Liquid oil, continental	Liquid oil, non-continental	Solid oil-derived
Chromium Cr	2.8E0 lb/TBtu (3.0E-2 lb/GWh)	2.9E0 lb/TBtu (3.0E-2 lb/GWh)	5.5E0 lb/TBtu (6.0E-2 lb/GWh)	3.1E+1 lb/TBtu (3.0E-1 lb/GWh)	8.0E-1 lb/TBtu. (2.0E-2 lb/GWh).
Cobalt, Co	8.0E-1 lb/TBtu (8.0E-3 lb/GWh)	1.2E0 lb/TBtu (2.0E-2 lb/GWh)	2.1E+1 lb/TBtu (3.0E-1 lb/GWh)	1.1E+2 lb/TBtu (1.4E0 lb/GWh)	1.1E0 lb/TBtu. (2.0E-2 lb/GWh).
Lead, Pb	1.2E0 lb/TBtu (2.0E-2 lb/GWh)	1.9E+2 lb/MMBtu (1.8E0 lb/MWh)	8.1E0 lb/TBtu (8.0E-2 lb/GWh)	4.9E0 lb/TBtu (8.0E-2 lb/GWh)	8.0E-1 lb/TBtu. (2.0E-2 lb/GWh).
Manganese, Mn	4.0E0 lb/TBtu (5.0E-2 lb/GWh	2.5E0 lb/TBtu (3.0E-2 lb/GWh)	2.2E+1 lb/TBtu (3.0E-1 lb/GWh)	2.0E+1 lb/TBtu (3.0E-1 lb/GWh)	2.3E0 lb/TBtu. (4.0E-2 lb/GWh).
Mercury, Hg	NA	NA	2.0E-1 lb/TBtu (2.0E-3 lb/GWh)	4.0E-2 lb/TBtu (4.0E-4 lb/GWh)	NA.
Nickel, Ni	3.5E0 lb/TBtu (4.0E-2 lb/GWh)	6.5E0 lb/TBtu (7.0E-2 lb/GWh)	1.1E+2 lb/TBtu (1.1E0 lb/GWh)	4.7E+2 lb/TBtu (4.1E0 lb/GWh)	9.0E0 lb/TBtu. (2.0E-1 lb/GWh).
Selenium, Se	5.0E0 lb/TBtu (6.0E-2	2.2E+1 lb/TBtu (3.0E-1	3.3E0 lb/TBtu (4.0E-2	9.8E0 lb/TBtu (2.0E-1	1.2E0 lb/TBtu. (2.0E-2

Table 5--Alternate Emission Limitations for Existing Coal- and Oil-Fired EGUs

Subcategory/ Pollutant	Coal-fired EGUs	IGCC	Liquid oil, continental	Liquid oil, non-continental	Solid oil-derived
	lb/GWh)	lb/GWh)	lb/GWh)	lb/GWh)	lb/GWh).

NA = Not applicable.
fna Includes Hg.

Table 6--Alternate Emission Limitations for New Coal- and Oil-Fired EGUs

Subcategory/ Pollutant	Coal-fired EGUs	IGCC fna	Liquid oil, continental, lb/GWh	Liquid oil, non-continental, lb/GWh	Solid oil-derived
SO[2]	4.0E-1 lb/MWh	4.0E-1 lb/MWh	NA	NA	4.0E-1 lb/MWh
Total non-mercury metals	6.0E-2 lb/GWh	4.0E-1 lb/GWh	2.0E-4 lb/MWh fnb	7.0E-3 lb/MWh fnb	6.0E-1 lb/GWh
Antimony, Sb	8.0E-3 lb/GWh	2.0E-2 lb/GWh	1.0E-2	8.0E-3	8.0E-3 lb/GWh
Arsenic, As	3.0E-3 lb/GWh	2.0E-2 lb/GWh	3.0E-3	6.0E-2	3.0E-3 lb/GWh
Beryllium, Be	6.0E-4 lb/GWh	1.0E-3 lb/GWh	5.0E-4	2.0E-3	6.0E-4 lb/GWh
Cadmium, Cd	4.0E-4 lb/GWh	2.0E-3 lb/GWh	2.0E-4	2.0E-3	7.0E-4 lb/GWh

Table 6--Alternate Emission Limitations for New Coal- and Oil-Fired EGUs

Subcategory/ Pollutant	Coal-fired EGUs	IGCC fna	Liquid oil, continental, lb/GWh	Liquid oil, non-continental, lb/GWh	Solid oil-derived
Chromium, Cr	7.0E-3 lb/GWh	4.0E-2 lb/GWh	2.0E-2	2.0E-2	6.0E-3 lb/GWh
Cobalt, Co	2.0E-3 lb/GWh	4.0E-3 lb/GWh	3.0E-2	3.0E-1	2.0E-3 lb/GWh
Lead, Pb	2.0E-3 lb/GWh	9.0E-3 lb/GWh	8.0E-3	3.0E-2	2.0E-2 lb/GWh
Mercury, Hg	NA	NA	1.0E-4	4.0E-4	2.0E-3 lb/GWh
Manganese, Mn	4.0E-3 lb/GWh	2.0E-2 lb/GWh	2.0E-2	1.0E-1	7.0E-3 lb/GWh
Nickel, Ni	4.0E-2 lb/GWh	7.0E-2 lb/GWh	9.0E-2	4.1E0	4.0E-2 lb/GWh
Selenium, Se	6.0E-3 lb/GWh	3.0E-1 lb/GWh	2.0E-2	2.0E-2	6.0E-3 lb/GWh

NA = Not applicable.
fna Based on best-performing similar source.
fnb Includes Hg.

As noted elsewhere in this preamble, we are finalizing a requirement to use filterable PM as a surrogate for the non-mercury metallic HAP and HCl as a surrogate for the acid gas HAP for all subcategories of coal-fired EGUs and for the solid oil derived fuel-fired EGUs. For all liquid oil-fired EGUs, we are finalizing a requirement to use filterable PM as a surrogate for the total metallic HAP, and we are finalizing HCl and HF limits.

In addition, we are finalizing alternative standards for certain HAP for some subcategories. The alternative pollutants and subcategories are as follows: (1) SO_2 as a surrogate to HCl for all subcategories with add-on FGD systems (except liquid oil-fired subcategories as there were no existing units from which to base an alternate SO[2] limit); (2) individual non-mercury metallic HAP as an alternate to filterable PM for all subcategories (except that it includes Hg for liquid oil-fired subcategories); and (3) total non-mercury metallic HAP as an alternate to filterable PM for all subcategories (except that it includes Hg for liquid oil-fired subcategories). These alternative standards are discussed elsewhere in this preamble.

We are finalizing a beyond-the-floor standard for Hg only for all existing coal-fired units designed for low rank virgin coal based on the use of activated carbon injection (ACI) for Hg control, as described elsewhere in this preamble. The EPA has determined that this beyond-the-floor level is achievable after considering the relevant CAA section 112(d)(2) provisions.

As noted elsewhere in this preamble, we are also finalizing a compliance assurance option that would allow you to monitor liquid oil fuel moisture to demonstrate that fuel moisture content is no greater than 1.0 percent. Provided that demonstration is made, you will not have to conduct additional testing and monitoring to demonstrate compliance with the HCl and HF emission limits for units in both liquid oil subcategories (*i.e.*, continental and non-continental).

Pursuant to CAA section 112(h), we are finalizing a work practice standard for organic HAP, including emissions of dioxins and furans, for all subcategories of EGUs. The work practice standard being finalized

requires the implementation of periodic burner tune-up procedures described elsewhere in this preamble. We are finalizing work practice standards because the significant majority of data for measured organic HAP emissions from EGUs are below the detection levels of the EPA test methods, even when long duration (around 8 hour) test runs are considered. As such, we consider it impracticable to measure emissions from these units. As discussed at proposal, we believe the inaccuracy of a majority of measurements, coupled with the extended sampling times used, allow a work practice standard under CAA section 112(h) to apply to these HAP.[306] We believe that a work practice standard will lead to a better environmental outcome than would be obtained through a requirement to measure a pollutant for which results may or may not be obtained. We believe that the work practice standard will result in actions being taken that will reduce emissions of these HAP.

In addition, as discussed below, we are creating a subcategory for limited use liquid oil-fired electric utility steam generating unit with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input and we are establishing work practice standards applicable to such units pursuant to CAA section 112(h).

We are finalizing that new or existing EGUs are "coal-fired" if they combust coal more than 10 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15 percent of the annual heat input during any one calendar year

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[306] We would also note that the EPA, as a part of the Industrial Boiler MACT reconsideration proposal that was signed on December 2, 2011, is proposing to establish work practice standards for control of dioxins and furans from industrial boilers.

and meet the final definition of "fossil fuel-fired." We are finalizing that an EGU is considered to be in the coal-fired "unit designed for coal greater than or equal to 8,300 Btu/lb" subcategory if the EGU: (1) meets the final definitions of "fossil fuel-fired" and "coal-fired electric utility steam generating unit;" and (2) is not a coal-fired EGU in the "unit designed for low rank virgin coal" subcategory.

We are finalizing that the EGU is considered to be in the "unit designed for low rank virgin coal" subcategory if the EGU: (1) meets the final definitions of "fossil fuel-fired" and "coal-fired electric utility steam generating unit;" and (2) is designed to burn and is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) and that is constructed and operates at or near the mine that produces such coal.[307]

We are finalizing that the EGU is considered to be an IGCC unit if the EGU: (1) Combusts a synthetic gas derived from gasified coal or solid oil-derived fuel (*e.g.*, petroleum coke, pet coke), (2) meets the final definition of "fossil fuel-fired," and (3) is classified as an IGCC unit. We are not subcategorizing IGCC EGUs based on the source of the syngas used (e.g., coal, petroleum coke). Based on information available to the Agency, although the fuel characteristics of coal and petcoke are quite different, the syngas products from both feedstocks have similar HAP content and similar HAP

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[307] ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

emissions characteristics that can be controlled in a similar manner.[308]

We are finalizing that the EGU is considered to be in the "Continental liquid oil-fired" subcategory if (1) meets the final definitions of "oil-fired electric utility steam generating unit" and "fossil fuel-fired;" and (2) is located in the continental United States (U.S.).

We are finalizing that the EGU is considered to be "Non-continental liquid oil-fired" subcategory if (1) meets the final definitions of "oil-fired electric utility steam generating unit" and "fossil fuel-fired;" and (2) is located outside continental U.S.

We are finalizing that the EGU is considered to be "solid oil-derived fuel-fired" if (1) the EGU is not a coal-fired EGU and burns solid oil-derived fuel (*e.g.*, petroleum coke, pet coke); and (2) meets the final definitions of "oil-fired electric utility steam generating unit" and "fossil fuel-fired."

We are finalizing that the EGU is considered to be a "limited-use liquid oil-fired" if (1) the EGU meets the final definitions of "oil-fired electric utility steam generating unit" and "fossil fuel-fired;" and (2) has an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing.

E. What are the requirements during periods of startup, shutdown, and malfunction?

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[308] U.S. Department of Energy, Wabash River Coal Gaification Repowering Project. Project Performance Summary; Clean Coal Technology Demonstration Program. DOE/FE-0448. July 2002. EPA-HQ-OAR-2009-0234-2933.

As discussed below in section VI.E., for startup and shutdown, the requirements have changed since proposal. For periods of startup and shutdown, the EPA is finalizing work practice standards in lieu of numeric emission limits. Numeric emission limits apply for all other periods for all pollutants, except organic HAP. For malfunctions, the EPA is finalizing an affirmative defense for exceedances of the numerical emission limits that are caused by malfunctions.

F. What are the testing and initial compliance requirements?

We are requiring that you, as an owner or operator of a new or existing coal- or oil-fired EGU, must conduct performance tests to demonstrate compliance with all applicable emission limits. For units using certified continuous emissions monitoring systems (CEMS) that directly measure the regulated pollutant under final 40 CFR part 63, subpart UUUUU (*e.g.*, Hg CEMS, HCl CEMS, HF CEMS, SO_2 CEMS (where an SO[2] limit applies as the alternative equivalent standard)), or sorbent trap monitoring systems, the initial performance test consists of all valid data recorded with the certified monitoring system in the first 30 boiler operating days of data collected with the certified monitoring system prior to the initial compliance demonstration date specified in § 63.10005. A source may also elect to use a PM CEMS to demonstrate compliance with the filterable PM emission limit. If this option is selected, then the same provisions as noted above for other CEMS will apply. (Note that EPA anticipates that the PM monitoring device that may most often will be used is a PM continuous parameter monitoring system (CPMS) in conjunction with an operating limit, as more fully

described below.) For units and pollutants not being monitored via CEMS, the owner or operator of an affected unit must perform the initial performance testing in accordance with established EPA reference test methods or the voluntary consensus standard methods incorporated by reference. You, as the owner or operator of an affected unit, must conduct the following compliance tests where applicable:

(1) For coal-fired units, IGCC units, and solid oil-derived fuel-fired units, if you elect to comply with the filterable PM emission limit, you must conduct filterable PM emissions testing using EPA Method 5 from Appendix A to part 60 of chapter 40 to determine initial compliance. Alternatively, if you elect to comply with the total non-mercury HAP metals emission limit or the individual non-mercury HAP metals emissions limits, you must conduct HAP metals testing using EPA Method 29 from Appendix A to part 60 of chapter 40. Note for this rule that the filter temperature for each Method 5 or 29 emissions test must be maintained at 160 [degrees] +/- 14 [degrees] C (320 [degrees] +/- 25 [degrees] F), and the material in Method 29 impingers must be analyzed for metals content. Whenever metals testing is performed with Method 29, you must report the front half and back half analytical fractions separately.

(2) For coal-fired, IGCC, and solid oil-derived fuel-fired units, you must use a Hg CEMS or a sorbent trap monitoring system for both initial compliance and continuous compliance using the continuous Hg monitoring provisions of Appendix A to 40 CFR part 63, subpart UUUUU, except where the low emitting EGU (LEE) requirements apply (see below). The initial performance test consists of all valid data recorded with the certified Hg monitoring system in

the 30 boiler operating days of data collected with the certified monitoring system by the initial compliance demonstration date specified in § 63.10005.

(3) For coal-fired and solid oil-derived fuel-fired units and new or reconstructed IGCC units that employ FGD technology and elect to meet the alternative SO_2limit in place of the HCl limit, you need not conduct an initial stack test for HCl or. Instead, the 30 boiler operating days of data collected with the certified SO_2 CEMS by the initial compliance demonstration date specified in § 63.10005 are used to determine initial compliance, and the SO[2] CEMS is used thereafter to demonstrate continuous compliance. If you instead opt to meet the HCl limit and use an HCl CEMS for compliance, you need not conduct an initial stack test for HCl. Instead, the 30 boiler operating days of data collected with the certified HCl CEMS by the initial compliance demonstration date specified in § 63.10005 are used to determine initial compliance. For units not using the SO[2] or HCl CEMS options, you must conduct an initial stack test for HCl using EPA Method 26, 26A, or 320 from Appendix A to part 60 of chapter 40. You may use EPA Method 26 or 320 or ASTM Method D6348-03 (Reapproved 2010) with additional quality assurance if no entrained water droplets exist in the exhaust gas, but you must use Method 26A if entrained water droplets exist in the exhaust gas.

(4) For liquid oil-fired units, you must conduct initial performance testing as follows. If you elect to meet the filterable PM limit instead of the non-mercury metals limit (total or individual), then use Method 5 with the filter material maintained at 160 [degrees] +/- 14 [degrees] C (320 [degrees] +/- 25 [degrees] F). Alternatively, you may use a PM CEMS as discussed

elsewhere in this preamble. If you elect to meet either the total or individual HAP metals limit, you will use Method 29 for all non-mercury HAP metals. For Hg, conduct emissions testing using EPA Method 29 or 30B from Appendix A to part 60 of chapter 40, or ASTM Method D6784-02 (Reapproved 2008). For acid gases, conduct HCl and HF testing using EPA Method 26A, 320, or 26; or you may elect to comply by using an HCl CEMS and/or an HF CEMS; or under certain conditions you may choose to demonstrate compliance by measuring fuel moisture to demonstrate that moisture content is no greater than 1.0 percent. You must measure daily if fuel is delivered continuously or per shipment if fuel is delivered on a batch basis, or you may use a fuel moisture content certification provided by your fuel supplier. If you use a CEMS, then use the 30 boiler operating days of data collected with the certified monitoring system by the initial compliance demonstration date specified in § 63.10005 to determine initial compliance.

(5) For the required performance stack tests, if you are demonstrating compliance with a heat-input based standard, you must conduct concurrent O[2] or carbon dioxide (SO_2) emission testing using EPA Method 3A or 3B from appendix A to part 60 of chapter 40 or ANSI/ASME PTC 19.10-1981 and then use an appropriate equation, selected from among Equations 19-1 through 19-9 in EPA Method 19 from appendix A to part 60 of chapter 40, to convert measured pollutant concentrations to lb/MMBtu values. Multiply the lb/MMBtu value by one million to get the lb/TBtu value (where applicable). If you choose to meet an electrical output-based emissions limit, you must also collect concurrent stack gas flow rate and electrical production data.

(6) For an existing unit that you believe will qualify as LEE for Hg, you must conduct an initial Method 30B test over 30 days and follow the calculation procedures in the final rule to document a potential to emit less than 10 percent of the applicable Hg emissions limit or less than 29 pounds of Hg per year. If your unit qualifies as a LEE for Hg, you must conduct subsequent performance tests on an annual basis to demonstrate that the unit continues to qualify. For all other pollutants, you must conduct the initial compliance test, and then all other required tests over a 3-year period, and in all such tests, your emission results must be less than 50 percent of the applicable emission limit. If you qualify as a LEE on that basis, you must conduct subsequent performance tests every 3 years to demonstrate that the unit continues to qualify.

(7) You may use results from tests conducted no earlier than 12 months before the compliance date of this rule as the initial performance test for an applicable pollutant, provided that:

a. You certify and keep records demonstrating that no significant changes have occurred,

b. Tests were conducted using methods allowed in this rule in accordance with § 63.10007 and Table 5,

c. You have records of all parameters needed to convert results to units of the standard for the entire period, and

d. For a CEMS-based performance test, you have all the required data for the entire 30-boiler operating day rolling average period.

Operating Limit for PM CEMS

Under the final rule, you may elect to comply continuously with an operating limit, established during the initial performance test, to demonstrate continuous compliance with the filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals limit. You will use a PM CPMS to monitor compliance with the operating limit. The PM CPMS operating principle must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal. Meeting the operating limit serves as your demonstration of continuous compliance with the filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals limit. As mentioned earlier, if you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals. As noted below, when you use this operating limit, you can reduce stack testing frequency to demonstrate ongoing compliance. You may also opt to install and operate a PM CEMS certified in accordance with Performance Specification 11 and Procedure 2 of 40 CFR part 60, Appendices B and F, respectively. If you elect to use this option, then the requirements for quarterly testing with Method 5, or annual testing and use of a PM CPMS, are no longer applicable.

Dioxins/Furans and Non-Dioxin/Furan Organic HAP

For dioxins and furans and non-dioxin/furan organic HAP, you must submit documentation that you have conducted a combustion process tune-up, a thorough

equipment inspection, and an optimization to minimize generation of CO and NO[X], all meeting the requirements of this final rule. The work practice standard involves maintaining and inspecting the burners and associated combustion controls, tuning the specific burner type to optimize combustion, obtaining and recording CO and NO[X] values before and after burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. You must collect CO and NO[X] data and may use portable analyzers (which include handheld or similar devices) to monitor and verify the results. The specific details are addressed in 40 CFR 63.10021 of the final rule.

This same work practice standard also applies in place of any emission limits for Hg, non-mercury metals HAP, acid gas HAP, dioxins and furans, and non-dioxin/furan organic HAP from a limited-use, liquid oil-fired EGU (*i.e.*, a unit that has an annual capacity factor on oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater). The EPA established this subcategory in response to comments and a further analysis of the units within this subcategory in the ICR database. For these units, EPA believes that the required work practice standards are appropriate and consistent with the requirement of CAA section 112(h).

G. What are the continuous compliance requirements?

To demonstrate continuous compliance with the emission limitations, the final rule includes the following requirements:

(1) *Use of CEMS.* Where a CEMS or a sorbent trap monitoring system is used for demonstrating initial compliance, you also must use the CEMS or sorbent

trap monitoring system on a continuous basis to demonstrate ongoing compliance with the numerical emission limits. CEMS or sorbent trap monitoring system data are not used to determine compliance with the work practice standards applicable during periods of startup and shutdown, but sources that install a CEMS or a sorbent trap monitoring system to demonstrate compliance with the numerical emission limits must operate the system at all times, as EPA intends to evaluate the continuous monitoring data from start-up and shutdown periods as discussed below. You must calculate a rolling average for each successive 30-boiler operating day rolling average period. All valid data collected during each successive period will be used to demonstrate compliance, except for data collected during periods of startup and shutdown; during those periods, the owner or operator must meet work practice requirements instead of the numerical emission limits. There is no numerical minimum data availability required to constitute a valid 30-boiler operating day rolling average; however, you must monitor at all times that the process is in operation (including during startups and shutdowns, although emissions during these periods are not included in the 30-boiler operating day average). You must operate, maintain, and quality-assure the CEMS or sorbent trap monitoring systems in accordance with the provisions in 40 CFR 63.10010 and Appendix A and B of the final rule (for Hg, HCl, and HF CEMS), in accordance with Performance Specification 11 in Appendix B to 40 CFR part 60 and Procedure 2 in Appendix F to part 60 (for PM CEMS used for direct compliance), or in accordance with 40 CFR part 75 (for SO_2 CEMS, and certain ancillary monitors such as a diluent or moisture monitor).

For each unit using HCl, HF, SO_2, PM, or Hg CEMS or a sorbent trap monitoring system for continuous compliance, you must install, certify, maintain, operate and quality-assure the additional CEMS (*e.g.*, CEMS that measure O_2 or CO_2 concentration, stack gas flow rate, and, if default moisture values are not used, moisture content) needed to convert pollutant concentrations to units of the emission standards or operating limits. Where appropriate, you must certify and quality-assure these additional CEMS according to 40 CFR part 75.

For HCl and HF CEMS, the EPA is adding monitoring provisions as Appendix B to 40 CFR part 63, subpart UUUUU. Appendix A references performance specification (PS) 15 of Appendix B to 40 CFR part 60 for Fourier Transform Infrared (FTIR) CEMS for procedures to certify and conduct ongoing quality assurance on these FTIR CEMS. In addition, we expect to publish a PS specific to HCl CEMS in the near future (prior to the compliance date of this rule). In the meantime, you may petition the Administrator under the procedure given in *40 CFR 63.7(f)* for an alternative approach to compliance monitoring or testing for HCl or any other regulated pollutant.

When using a sorbent trap monitoring system, you may use each pair of sorbent traps to collect Hg samples for no more than 15 boiler operating days. Under the general duty to monitor at all times, you must replace traps in a timely manner to ensure that Hg emissions are sampled continuously.

For Hg monitoring, the EPA is adding Hg monitoring provisions as Appendix A to 40 CFR part 63, subpart UUUUU, and requiring use of these provisions to document continuous compliance with the rule for coal-fired, IGCC, and solid oil derived-fired units

that cannot qualify as LEEs. Appendix A consolidates all Hg monitoring provisions.

Today's rule provides two basic Hg continuous monitoring options: Hg CEMS and sorbent trap monitoring systems. Appendix A requires initial certification and periodic quality assurance (QA) testing of the Hg CEMS and sorbent trap monitoring systems. The certification tests required for the Hg CEMS are a 7-day calibration error test; a linearity check, using NIST-traceable elemental Hg standards; a 3-level system integrity check (similar to a linearity check), using NIST-traceable oxidized Hg standards; a cycle time test; and a relative accuracy test audit (RATA). Table A-1 of Appendix A summarizes the performance specifications for the required certification tests. For ongoing QA of the Hg CEMS, Appendix A requires daily calibrations, weekly single-point system integrity checks, quarterly linearity checks (or 3-level system integrity checks), and annual RATAs. Table A-2 in Appendix A summarizes these ongoing QA test requirements and the applicable performance criteria for Hg CEMS, which are consistent with those published in support of CAMR and are, thus, familiar to the industry.

For sorbent trap monitoring systems, a RATA is required for initial certification, and annual RATAs are required for ongoing QA. The performance specification for these RATAs is the same as for the RATAs of the Hg CEMS. Bias adjustment of the measured Hg concentration data is not required. For day-to-day operation of the sorbent trap system, Appendix A requires you to follow the procedures and QA/QC criteria in PS 12B in Appendix B to 40 CFR part 60. PS 12B is nearly identical to the Appendix K to 40 CFR part 75, published in support of CAMR and

with which the industry is familiar. The 40 CFR part 75 concepts of:

a. Determining the due dates for certain QA tests on the basis of "QA operating quarters" and

b. Grace periods for certain QA tests apply to both Hg CEMS and sorbent trap monitoring systems. Mercury concentrations measured by Hg CEMS or sorbent trap systems are used together with hourly flow rate, diluent gas, moisture, and electrical load data, to express the Hg emissions in units of the rule, on an hourly basis (*i.e.*, lb/TBtu or lb/GWh). Section 6 of Appendix A provides the necessary equations for these unit conversions.

For HCl and HF CEMS, the EPA is adding monitoring provisions as Appendix B to 40 CFR part 63, Subpart UUUUU. Appendix A references performance specification (PS) 15 of Appendix B to 40 CFR part 60 for Fourier Transform Infrared (FTIR) CEMS for procedures to certify and conduct ongoing quality assurance on these FTIR CEMS. In addition, we expect to promulgate a generic PS specific to HCl CEMS prior to the compliance date of this rule. In the meantime, you may petition the Administrator under the procedure given in *40 CFR 63.7(f)* for an alternative approach to compliance monitoring or testing for HCl or any other regulated pollutant.

(2) *Use of stack tests.* If you demonstrate initial compliance on the basis of a stack test, you must demonstrate continuous compliance by conducting periodic stack tests on a quarterly basis. This includes filterable PM (or non-mercury HAP metals) and HCl from coal-fired and solid oil-derived fuel-fired EGUs, and filterable PM (or HAP metals) and HCl and HF from liquid oil-fired EGUs with the following exceptions:

a. If you use a PM CPMS and associated operating limit, you may conduct the applicable Method 5 or Method 29 test once annually rather than quarterly, in which case you must re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule includes basic quality checks that the PM CPMS must meet and a requirement for you to develop and follow a site-specific monitoring plan to be approved by the delegated authority. You must demonstrate compliance with the operating limit by using all valid hourly data collected during each successive 30-boiler operating day period rolled daily. The 30-boiler operating day rolling average is calculated by all of the valid hourly average PM CPMS output values collected for the 30 boiler operating days (excluding hours of startup and shutdown; *See* section V.E. of this preamble).

b. If you combust liquid fuels and if your fuel moisture content is no greater than 1.0 percent, you may demonstrate ongoing compliance with HCl and HF emissions limits by:

i. Measuring fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis;

ii. Measuring fuel moisture content daily if your fuel arrives on a continuous basis; or

iii. Obtaining and maintaining a fuel moisture certification from your fuel supplier.

Should the moisture in your liquid fuel be more than 1.0 percent, you must

i. Conduct HCl and HF emissions testing quarterly and establish site-specific monitoring to

demonstrate continued acid gas control performance between periodic tests, or

ii. Use an HCl CEMS and/or HF CEMS.

c. If your existing unit qualifies as an LEE for Hg, you must conduct another 30-day Method 30B performance test on your unit once per year to reestablish that the unit continues to qualify as a LEE for Hg. If the results of the LEE test show that the unit exceeds 10 percent of the emissions limit or exceeds the potential to emit 29 pounds of Hg per year, you will lose LEE status for the unit. You can regain LEE status for that unit if every required performance test for a 3-year period shows that emissions from the unit did not exceed the LEE limit. If LEE status is lost for a solid fuel unit, you must commence quarterly performance testing until you install, certify, and operate a Hg CEMS or a sorbent trap monitoring system, and you must complete the installation and certification within 6 months of losing LEE status; for a liquid fuel unit, you must commence quarterly performance testing.

d. If a liquid oil-fired EGU has an annual capacity factor on oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater, you must demonstrate continuous compliance with the applicable work practice standard by conducting at least once every 36 calendar months (48 calendar months if a neural network is employed) a combustion process tune-up, a thorough equipment inspection, and an optimization to minimize generation of CO and NO_X, all meeting the requirements of this final rule. You must maintain and inspect the burners and associated combustion controls, tuning the specific burner type to optimize combustion, obtaining and recording CO and NO_X values before and after burner adjustments,

keeping records of activity and measurements, and submitting a report for each tune-up conducted. You must collect CO and NO_x data using portable analyzers (which typically include handheld or similar devices). Specific details are addressed in 40 CFR 63.10021 of the final rule. In addition, you must record boiler operating hours, by fuel type, in each calendar quarter.

e. The rule allows a grant of LEE status to existing units with test results that show a history of low, non-mercury emissions. As mentioned earlier, LEE status reduces testing frequency for units. After a 3-year period during which every emissions test for a specific pollutant shows emissions no greater than 50 percent of the emissions limit, you may reduce the emissions testing frequency for that specific non-mercury pollutant to once every 36 months. If any subsequent emissions test for that pollutant exhibits emissions greater than 50 percent of the emissions limit, you must revert to the original emissions testing frequency until you re-establish a 3-year period of very low emissions no greater than 50 percent of the standard.

f. For liquid oil-fired units that demonstrate continuous compliance with quarterly performance tests for HCl and HF emission limits rather than through use of HCl and HF CEMS, the final rule requires a site-specific monitoring plan in addition to the quarterly tests. For these pollutants, there is unlikely to be any existing underlying monitoring (such as compliance assurance monitoring) that serves as an additional tool to ensure the source's operations remain consistent with operating conditions during a recent successful performance test. The requirement for a site-specific monitoring plan fills this gap and ensures

that in between tests, the source continues to operate in a manner designed to maintain HCl and HF emissions in compliance with the emission limits under this rule. The appropriate parameters to monitor will depend on the compliance strategy employed by a specific source, and thus EPA is enabling the monitoring approach to be established on a case-by-case basis. Given the relatively small number of these units and the other compliance options available, we anticipate that this approach will apply to a small set of units. The monitoring plan will identify the parameters monitored, the monitoring methods, the QA/QC elements that apply, and the data reduction elements (including appropriate averaging periods, as applicable). See 40 CFR 63.10000(c)(2)(ii).

(3) *Work practice standard.* For the performance tune-up work practice requirements, you must demonstrate continuous compliance by conducting the work practice at least once every 36 calendar months (48 calendar months if a neural network is employed). The work practice involves maintaining and inspecting the burners and associated combustion controls, tuning the specific burner type, as applicable, to optimize combustion, obtaining and recording CO and NO_x values before and after burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. A combustion tune-up will involve optimizing combustion of the unit consistent with manufacturer's instruction as applicable, or in accordance with best combustion engineering practice for that burner type.

H. What are the notification, recordkeeping and reporting requirements?

All new and existing sources in all subcategories must comply with certain requirements of the General

Provisions (40 CFR part 63, subpart A), which are identified in Table 9 of this final rule. The General Provisions include specific requirements for notifications, recordkeeping, and reporting. You must submit a notification of compliance status report for each unit, according to the schedule required by *40 CFR 63.9(h)* of the General Provisions, including a certification of compliance.

Except for units that use CEMS for continuous compliance, under this rule you must provide semiannual compliance reports, as required by *40 CFR 63.10(e)(3)* of subpart A, that indicate whether a deviation from any of the requirements in the rule occurred and whether or not any process changes occurred and compliance certifications were reevaluated. As discussed below, we are finalizing a requirement to use the 40 CFR part 75-based Emissions Collection and Monitoring Plan System (ECMPS) for reporting emissions and related data for units using CEMS for most pollutants. Also, as discussed below, for the PM CPMS, PM CEMS, and performance test results, we require you to use EPA's WebFIRE[309] database for reporting.

This rule requires you to keep certain records to demonstrate compliance with each emission limit and work practice standard. The General Provisions to 40 CFR part 63 specify these recordkeeping requirements (see Table 9 to this subpart). Among other specific records, you must keep the following:

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[309] WebFIRE is the Internet version of FIRE. The Factor Information Retrieval (FIRE) Data System is a database management system containing EPA's recommended emission estimation factors for criteria and HAP. It includes information about industries and their emitting processes, the chemicals emitted, and the emission factors themselves.

(1) All reports and notifications submitted to comply with this rule.

(2) Continuous monitoring data as required in this rule.

(3) Each instance in which you did not meet an emission limit, work practice requirement, operating limit, or other compliance obligation (*i.e.*, deviations from this rule).

(4) Daily hours of operation by each unit.

(5) As part of the general duty to keep all monitoring data, fuel moisture content of liquid fuel, if you elect to demonstrate compliance using that information.

(6) A copy of the results of all performance tests, monitor certifications, performance evaluations, or other compliance demonstrations conducted to demonstrate initial or continuous compliance with this rule.

(7) A copy of your site-specific performance evaluation test plans developed for this rule as specified in *40 CFR 63.8(e)*, if applicable.

(8) A copy of your acid gas control system parameter monitoring plan under 40 CFR 63.10000(c)(2)(ii).

You also must submit the following additional notifications:

(1) Notifications required by the General Provisions.

(2) Initial Notification no later than 120 calendar days after you become subject to this subpart.

(3) Notification of Intent to conduct performance tests and/or compliance demonstration at least 60 calendar days before the performance test and/or compliance demonstration is scheduled.

(4) Notification of Compliance Status 60 calendar days following completion of the performance test and/or compliance demonstration.

Electronic reporting is becoming a common element of modern life (as evidenced by electronic banking and income tax filing), and the EPA is beginning to require electronic submittal of environmental data. Electronic reporting is already common in environmental data collection and many media offices at EPA are reducing reporting burden for the regulated community by embracing electronic reporting systems as an alternative to paper-based reporting.

One of the major benefits of reporting electronically is standardization, to the extent possible, of the data reporting formats that provides more certainty to users of what data are required in specific reports. For example, electronic reporting software allows for more efficient data submittal and the software's validation mechanism helps industry users submit fewer incomplete reports. This alone saves industry report processing resources and reduces transaction times. Standardization also allows for development of efficient methods to compile and store much of the documentation required to be reported by this rule.

Use of Electronic Reporting System

We are requiring that you submit certain reports electronically. In addition to supporting regulation development, control strategy development, and other air pollution control activities, having an electronic database populated with these reports will save industry, state, local, tribal agencies, the public, and the EPA significant time, money, and effort while also improving the transparency and quality of emission inventories and, as a result, air quality regulations.

The reports to be submitted electronically include all performance test reports, notification of compliance status reports, compliance, and continuous monitoring data summaries specified in 40 CFR 63.10031 of this rule. Performance tests are required to be conducted as described in *40 CFR 63.7* of the General Provisions. The data that must be submitted as the performance test report are also described in *40 CFR 63.7*. These data must be submitted (except in limited cases) to EPA's WebFIRE database by using the electronic reporting tool (ERT) and the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX), as described below. The data requirements for the notification of compliance status and compliance reports are described in detail in the regulatory text (40 CFR 63.10031) of this rule, but they essentially mirror the requirements in *40 CFR 63.6* of the General Provisions. These reports will also be submitted to WebFIRE using an electronic form found in CEDRI and through the CDX as described below. As required in 40 CFR 63.10031(f)(2) of the final rule, the continuous monitoring summaries are required to be submitted quarterly. The quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the PM CPMS. These reports will also be submitted to WebFIRE using an electronic form found in CEDRI and through the CDX, as described below. This same approach will apply if a source elects to use a PM CEMS or receives approval to use a HAP metals CEMS as an alternative monitoring method.

The availability of electronic reporting for sources subject to the Subpart UUUUU will provide efficiency, improved services, better accessibility of information,

and more transparency and accountability. Additionally, submittal of these required reports electronically provides significant benefits for regulatory agencies, industry, and the public. The compliance data electronic reporting system (CEDRI and CDX) is being developed such that once a facility's initial data entry into the system is established and a report is generated, subsequent data submittal will only consist of electronic updates to existing information in the system. Such a system will effectively reduce the burden associated with submittal of data and reports by reducing the time, costs, and effort required to submit and update hard copies of documentation. State, local, and tribal air pollution control agencies will also benefit from having access to the more streamlined and accurate electronic data submitted to the EPA. Electronic reporting will allow for an electronic review process rather than a manual data assessment, making review and evaluation of the source-provided data and calculations easier and more efficient. Electronic reporting will also benefit the public by generating a more transparent review process and increasing the ease and efficiency of data accessibility. Furthermore, electronic reporting will reduce the burden on the regulated community by reducing the effort involved in data collection and reporting activities. In the future, we anticipate there will be fewer and less substantial data collection requests in conjunction with prospective required residual risk assessments or technology reviews. Electronic reporting will substantially reduce this burden, because the EPA will already have these data available and consolidated in an electronic database named WebFIRE. We anticipate that using electronic reporting for the required reports will result in an overall reduction in reporting costs; for a discussion

of the economic and cost impacts of electronic reporting, see section XII.D. of this preamble.

Another benefit of electronic data submittal is that these data will greatly improve the overall quality of existing and new emissions factors by supplementing the pool of emissions test data for establishing emissions factors and by ensuring that the factors are more representative of current industry operational procedures. A common complaint heard from industry and regulators is that emission factors are outdated or not representative of a particular source category. With timely receipt and incorporation of data from most performance tests, the EPA will be able to ensure that emission factors, when updated, represent the most current range of operational practices.

Data entry of these electronic reports will be through the CEDRI that is accessed through EPA's CDX (*www.epa.gov/cdx*). Data submitted electronically through CEDRI will be stored in CDX as an official copy of record.

Once you have accessed CEDRI, you will select the applicable subpart for the report that you are submitting. You will then select the report being submitted, enter the data into the form, and click on the submit button. In some cases, such as with submittal of a notification of compliance status report, you will select the report icon, enter basic facility information, and then upload the report in a specified file format.

In addition, we believe that there will be value in allowing other reporting forms to be developed and used in cases where the other reporting forms can provide an alternate electronic file consistent with EPA's form output format. This approach has been

used successfully to provide alternatives for other electronic forms (*e.g.*, income tax submittal).

In cases where performance test data are to be submitted to the EPA, you must enter the performance test data and information into the electronic reporting tool (ERT) which can be accessed at *http://www.epa.gov/ttn/chief/ert/index.html*. In CEDRI, the user must then upload the ERT file. CEDRI submits a copy of the ERT project data file directly to WebFIRE where the data are made available. Where performance test reports are submitted, WebFIRE notifies the appropriate state, local, or tribal agency contact that an ERT project data file was received from the source.

Submitting performance test data electronically to the EPA will apply only to those performance tests conducted using test methods that will be supported by the ERT. The ERT contains a specific electronic data entry form for most of the commonly used EPA reference methods. A listing of the pollutants and test methods supported by the ERT is available at the ERT Web site listed above.

I. Submission of Emissions Test Results to the EPA

The EPA has determined that harmonization of the monitoring and reporting requirements of this final rule with 40 CFR part 75 is appropriate, where the affected industry already has a well-defined system for continuous monitoring and reporting of emissions under that part. Therefore, the Agency is finalizing monitoring and reporting requirements for most CEMS that are consistent with 40 CFR part 75. You must report CEMS data (other than PM CEMS data or data from alternative monitoring subject to site-specific approval such as a HAP metals CEMS) to the

EPA electronically, on a quarterly basis, using the ECMPS.

The ECMPS process divides electronic data into three categories, the first of which is monitoring plan data. You must maintain the electronic monitoring plan separately and can update it at any time if necessary. The monitoring plan documents the characteristics of the affected units (*e.g.*, unit type, rated heat input capacity, etc.) and the monitoring methodology used for each parameter (*e.g.*, CEMS). The monitoring plan also describes the type of monitoring equipment used (hardware and software components), includes analyzer span and range settings, and provides other useful information. Nearly all coal-fired EGUs are subject to the ARP and thus have established electronic monitoring plans that describe their required SO_2, flow rate, CO_2 or O_2, and, in some cases, moisture monitoring systems. The EPA will adjust the ECMPS monitoring plan format to accommodate this same type of information for Hg, HCl, and HF CEMS, with the addition of a few codes for the new parameters.

The second type of data collected through ECMPS is certification and QA test data. These data include data from linearity checks, RATAs, cycle time tests, 7-day calibration error tests, and a number of other QA tests that are required to validate the emissions data. You may submit the results of these tests to the EPA as soon as you obtain the results, with one notable exception. Daily calibration error tests are not treated as individual QA tests, due to the large number of records generated each quarter. Rather, these tests must be included in the quarterly electronic reports, along with the hourly emissions data. The ECMPS system is set up to receive and process certification

and QA data from SO_2, CO_2, O_2, flow rate, and moisture monitoring systems that are installed, certified, maintained, operated, and quality-assured according to 40 CFR part 75. EGUs routinely submit these data to the EPA under the ARP and other emissions trading programs.

To accommodate the certification and QA tests for Hg CEMS, other CEMS, and sorbent trap monitoring systems, the structure and functionality of ECMPS needs relatively few changes, because most of the tests are the same as those required for other gas monitors. For reporting Hg, HCl, SO_2, and HF CEMS data under this rule, we are disabling ECMPS' 40 CFR part 75 bias test (which is required for certain types of monitors under the EPA's SO_2 and NO_X emissions trading programs). The bias adjustment of the data from these monitors is unnecessary for compliance with the rule.

The third type of data collected through ECMPS is the hourly emissions data, which, as previously noted, is reported on a quarterly schedule. You must submit reports within 30 days after the end of each calendar quarter. The emissions data format requires hourly reporting of all measured and calculated emissions values, in a standardized electronic format. You must report direct measurements made with CEMS, such as gas concentrations, in a Monitor Hourly Value (MHV) record. A typical MHV record for gas concentration includes data fields for:

(1) The parameter monitored (*e.g.*, SO_2);

(2) The unadjusted and bias-adjusted hourly concentration values (note that if bias adjustment is not required, only the unadjusted hourly value is reported);

(3) The source of the data, *i.e.*, a code indicating either that each reported hourly concentration is a quality assured value from a primary or backup monitor, or that quality-assured data were not obtained for the hour; and

(4) The percent monitor availability (PMA), which is updated hour-by-hour. This generic record structure could easily accommodate hourly average measurements from CEMS used under this rule.

The ECMPS reporting structure is quite flexible, which makes it useful for assessing compliance with various emission limits. The Derived Hourly Value (DHV) record allows calculations of a wide variety of quantities from the reported hourly emissions data. For instance, if an emission limit is expressed in units of lb/MMBtu, the DHV record can be used to report hourly pollutant concentration values in these units of measure, since the lb/MMBtu values can be derived from the hourly pollutant and diluent gas (CO_2 or O_2) concentrations reported in the MHV records. The ECMPS can also accommodate multiple DHV records for a given hour in which more than one derived value is required to be reported. The system will support reporting hourly data in the units of the emission standards (*e.g.*, lb/MMBtu, lb/TBtu, lb/GWh, etc.) when hourly Hg concentration data are reported through ECMPS using the DHV record, in conjunction with the appropriate equations and auxiliary information such as heat input and electrical load (all of which are reported hourly in the emissions reports).

One change in this rule from standard 40 CFR part 75 emissions data reporting is elimination of the requirement to provide substitute data calculations within ECMPS. The ARP and other emissions trading programs that report emissions data to the EPA using

40 CFR part 75 require provision of a complete data record. Emissions data are required to be reported for every unit operating hour. When CEMS are out of service, substitute data must be reported to fill in the gaps. However, for the purposes of compliance with a NESHAP, reporting substitute data during monitor outages is not necessary, as quantification of total mass emissions is not the focus of the rule. Hours when a monitoring system is out of service would be counted as hours of monitor down-time and may be a deviation from the monitoring requirements of this rule unless the rule provides an exception, as it does for routine quality control and maintenance activities.

In contrast to the CEMS-related data that would be submitted through ECMPS, you must submit reports of performance tests and PM CPMS data to EPA's WebFIRE database by using CEDRI that is accessed through EPA's CDX (*www.epa.gov/cdx*). You must submit performance test data in the file format generated through use of EPA's ERT (see *http://www.epa.gov/ttn/chief/ert/index.html*) within 60 days of performance test completion. Electronic data submittal requirements are described in section V.H. of this preamble.

Other notifications and reports not currently accepted by the electronic reporting system will be submitted in hardcopy form at this time.

VI. Summary of Significant Changes Since Proposal

The previous section described the requirements that EPA is finalizing in this rule. This section will discuss in greater detail the key changes EPA is making from the proposed. These changes result from EPA's review of the additional data and information

provided to us and our consideration of the many substantive and thoughtful comments submitted on the proposal. While our approach and methodology to establishing the standards remain the same, the changes make the final rule more flexible and cost-effective, reduce reliability concerns and improve clarity, while fully preserving, or improving, the public health and environmental protection required by the CAA.

A. Applicability

Since proposal, the EPA has made certain changes to the applicability provisions of the final rule to provide clarity. These changes do not change the universe of sources subject to the rule.

The EPA is revising a number of the proposed definitions and adding a definition for "natural gas-fired electric utility steam generating unit" in the final rule to provide clarity to the regulated community concerning the standards applicable to coal and oil-fired EGUs.

In the proposed rule, the EPA defined "[e]lectric utility steam generating unit" consistent with the CAA section 112(a)(8) definition:

A fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

40 CFR 63.10042.

We also indicated how we would determine whether units were coal-fired or oil-fired fired EGUs: "If an EGU burns coal (either as a primary fuel or as a supplementary fuel), or any combination of coal with another fuel (except solid waste as noted below), the unit is considered to be coal fired under this proposed rule. If a unit is not a coal-fired unit and burns only oil, or oil in combination with another fuel other than coal (except as noted below), the unit is considered to be oil fired under this proposed rule." *76 FR 25020.*

We proposed a definition for the term "fossil fuel-fired" because that term was not defined in the statute and we wanted to clarify the level of fossil fuel combustion necessary to satisfy the CAA section 112(a)(8) definition of EGU. The definition focused on coal and oil combustion because the EPA was only regulating coal- and oil-fired EGUs in this final rule. The proposed definition contained two primary elements: (1) the unit must be capable of combusting sufficient amounts of coal or oil to generate the equivalent of 25 megawatts electrical output; and (2) the unit must have fired coal or oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years. *76 FR 25025.* We further stated that for a unit to be "capable of combusting" coal or oil the unit must have a permit that authorized the combustion of coal or oil and also have the appropriate fuel handling facilities on-site. *Id.*

As explained in the proposed rule, natural gas-fired EGUs were not included in the December 2000 listing so such units that otherwise met the CAA section 112(a)(8) definition of EGU because of natural gas combustion are not subject to the final rule. In the

proposed rule, we stated that an EGU that "combusts natural gas exclusively or natural gas in combination with another fuel where the natural gas constitutes 90 percent or more of the average annual heat input during the previous 3 calendar years or 85.0 percent or more of the annual heat input during any one of those calendar years" was not subject to the rule. *Id.* The references to 90 percent natural gas combustion over 3 years and 85 percent natural gas combustion in any one year were included to align with the definitions of "fossil fuel-fired" so that it would be clear that units combusting primarily natural gas would not be considered coal-fired, oil-fired, or IGCC EGUs if they burned 10 percent or less of coal, oil, or synthetic gas derived from coal or solid oil over 3 years or 15 percent or less of such fuels in any one year. We did not intend to suggest that to be considered a fossil fuel-fired EGU a natural gas-fired unit that is not a coal-fired or oil-fired EGU would have to combust natural gas that exceeded the 10 percent/15 percent thresholds set forth in the proposed rule. In fact, in 40 CFR 63.9983 of the proposed rule, we stated that "[a]ny EGU that is not a coal- or oil-fired EGU and combusts natural gas more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years" is not subject to this subpart.

We further explained that the percentages included in the definition of "fossil fuel-fired" would prevent units that primarily combusted fuels other than fossil fuels from being subjected to the final rule:

Units that do not meet the definition of fossil-fuel fired would, in most cases, be considered IB units subject to one of the Boiler NESHAP. Thus, for

example, a biomass-fired EGU, regardless of size, that utilizes fossil fuels for startup and flame stabilization purposes only (*i.e.*, less than or equal to 250 MMBtu/hr and used less than 10.0 percent of the average annual heat input during the previous 3 calendar years or less than 15.0 percent of the annual heat input during any one of those calendar years) is not considered to be a fossil fuel-fired EGU under this proposed rule. The EPA has based its threshold value on the definition of "oil-fired" in the ARP found at *40 CFR 72.2*. As EPA has no data on such use for (*e.g.*) biomass co-fired EGUs because their use has not yet become commonplace, we believe this definition also accounts for the use of fossil fuels for flame stabilization use without inappropriately subjecting such units to this proposed rule. *Id.*

Thus, in the proposed rule, we intended to create thresholds to determine when a unit is fossil fuel-fired and for which fossil fuel the unit is fossil fuel-fired. We intended to include a unit combusting more than the defined amount of coal in one of the coal-fired EGU subcategories. If a unit is not coal-fired and it is combusting more than the defined amount of oil, we intended to include the unit in one of the oil-fired EGU subcategories. We also intended to make clear that EGUs that are neither coal-fired nor oil-fired but combust more than the defined amount of natural gas are natural gas-fired EGUs not subject to the final standards. However, the definitions, as proposed, were not sufficiently descriptive.

For example, we included a definition for "coal-fired electric utility steam generating unit" that did not include the requirement that the unit must combust coal for at least 10 percent of the heat input over 3 years or 15 percent of the heat input in any one year.

Instead, in the proposed rule we indicated that a unit was coal-fired if it burned coal in any amount. We did not intend to define a unit as coal-fired if it burned coal that accounted for 10 percent or less over 3 years or 15 percent of less in any one year, as that would be inconsistent with the definition of fossil fuel-fired and the definitions for the oil-fired EGU subcategories. Under the proposed rule construct, a unit that combusts mostly biomass and less than 10 percent coal over 3 years would not be a coal-fired EGU because it would not meet the "fossil fuel-fired" definition. But a unit burning mostly petroleum coke and less than 10 percent coal over 3 years might be considered a coal-fired EGU because it would meet the definition of "fossil fuel-fired" and be burning some coal, even though that level of coal combustion alone would not be sufficient to make the unit "fossil fuel-fired" for coal. That result is at odds with our intent. The same would hold true for an EGU that combusts mostly natural gas and less than 10 percent synthetic gas derived from coal over a 3-year period. Our proposal preamble makes clear that we did not intend this result because we specifically stated that units burning 90 percent or more natural gas over a 3-year period would be considered natural-gas fired EGUs. *76 FR 25025.*

In addition, we proposed to define "[u]nit designed to burn solid oil fuel subcategory" to include any EGU that burned a solid fuel derived from oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years, either alone or in combination with other fuels. We also included the 10 percent/15 percent thresholds in the definition for the liquid oil subcategory, but, as stated above, we did not include the thresholds in the definition of "coal-fired" EGU.

Therefore, there would be some confusion for a source that blended coal with solid oil derived fuel (*e.g.*, petroleum coke). For example, the owner or operator of an EGU that burned sufficient solid oil-derived fuel that accounted for 80 percent of the heat input in a given year and the remainder of the fuel was coal would not be sure which standard applied because the definitions in the proposed rule were internally inconsistent.

For these reasons, we are revising the definitions for "coal-fired electric utility steam generating unit," "integrated gasification combined cycle electric utility steam generating unit," and "oil-fired electric utility steam generating unit," and we are adding a definition of "natural-gas fired electric utility steam generating unit" as set out in 40 CFR 63.10042.

In addition to these changes, we are revising the definition of "fossil fuel-fired" based on comments. We are revising the definition to remove the heat input equivalent of 25 MW because commenters noted that the equivalency used (taken from 40 CFR part 60, subpart Da) could not be applied consistently because of differing boiler efficiencies. Commenters noted that owners/operators were familiar with the use of the "MW" term for the boilers and boilers include nameplate capacities that are readily identifiable.

We are also including a revision to the definition so that the fossil fuel combustion thresholds of 10 percent over 3 consecutive years and 15 percent in one year are evaluated after the applicable compliance date of the final rule on a rolling basis. Commenters correctly noted that some existing coal- and oil-fired EGUs will convert their units to alternative fuels (*e.g.*, natural gas or biomass) and if the definition were finalized as

proposed such units could be improperly subjected to the final standards.

The new definition is set out in 40 CFR 63.10042.

For clarity, we are also removing the definition of "[u]nit designed to burn liquid oil fuel subcategory," revising the definition of "[u]nit designed to burn solid oil fuel subcategory," adding definitions for the continental and non-continental liquid oil-fired EGU subcategories, and adding a definition of a limited-use liquid oil-fired EGU as set out in 40 CFR 63.10042.

In the proposed rule, we stated that we believed EGUs may at times not meet the definition of an EGU subject to this subpart. For example, we explained that there may be some cogeneration units that are determined to be covered under the Boiler NESHAP. Such unit(s) may make a decision to increase the proportion of production output being supplied to the electric utility grid, thus causing the unit(s) to meet the EGU cogeneration criteria (*i.e.*, greater than one-third of its potential output capacity and greater than 25 MW). In the preamble to the proposed rule, we indicated that a unit subject to one of the Boiler NESHAP that increases its electricity output and meets the definition of an EGU would be subject to the EGU NESHAP for the 6-month period after the unit meets the EGU definition. n310 *76 FR 25026.* Assuming the EGU did not meet the definition of an EGU following that initial occurrence, at the end of the 6-month period it would revert back to being subject to the Boiler NESHAP, or other applicable standard. We solicited comment on the extent to which situations like this might occur, how the EPA should address situations where units change applicability, and whether we should include provisions similar to those

included in the final CISWI (*40 CFR 60.2145*) to address such situations. *Id.*

n310 Although we clearly stated the intent to require sources to comply for 6 months after meeting the definition of an EGU, we inadvertently failed to include the provision in the proposed rule.

Several commenters asked the Agency to include provisions in the final rule that would address situations like the ones described in the preamble to the proposed rule. Because applicability to the final rule is based in part on the statutory definition of an EGU is CAA section 112(a)(8), similar to the situation with units combusting solid waste under CAA section 129(g)(1) (*e.g.*, CISWI Rule), we are adopting provisions in the final rule that are based on the fuel switching provisions of the final CISWI Rule (*See* Final CISWI Rule, *40 CFR 60.2145*). For example, a cogeneration unit that did not historically provide more than one third of its potential electrical output capacity to a power distribution system could change its output and provide more than 25 megawatts electrical output to any power distribution system for sale. Such units would be subject to MATS. If the cogeneration unit later reduced its output such that it no longer met the definition of an EGU, that source would nevertheless remain subject to MATS for at least 6 months from the date that the unit first qualified as an EGU.

In addition, we are finalizing a provision whereby you may opt to remain subject to the provisions of this final rule, unless you combust solid waste, in which case you are a solid waste incineration unit subject to standards under CAA section 129 (*e.g.*, 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste

Incineration Units), or subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units)). We believe the provision to opt to remain subject to this final rule will ameliorate conditions where EGUs may potentially move between NESHAP on a relatively frequent basis. Notwithstanding the provisions of this final rule, an EGU that starts combusting solid waste is subject to standards under CAA section 129, and the unit remains subject to those standards until the unit no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

The changes to the definitions described above provide clarity to sources, permitting agencies, and the public about the applicability of the rule and help ensure that sources are appropriately covered by the regulation.

B. Subcategories

In this final rule, the EPA is adding subcategories for limited-use oil-fired units and non-continental oil-fired units and revising the definitions for the coal-fired EGU subcategories.

The proposed rule subcategorized EGUs burning coal into two subcategories: EGUs designed for coal >/=8,300 Btu/lb and EGUs designed for virgin coal < 8,300 Btu/lb (low rank virgin coal). We received a number of comments indicating that the definition of the low rank virgin coal subcategory was technically deficient.

Under CAA section 112(d)(1), the Administrator has the discretion to "* * * distinguish among classes, types, and sizes of sources within a category or subcategory in establishing * * *" standards. The EPA

maintains that, normally, any basis for subcategorization (*i.e.*, class, type, or size) must be related to an effect on HAP emissions that is due to the difference in class, type, or size of the units. *See 76 FR 25036-25037.* The EPA believes it is not reasonable to exercise our discretion without such a difference because if sources can achieve the same level of emissions reductions notwithstanding a difference in class, type, or size, the purposes of CAA section 112 are better served by requiring a similar level of control for all such units in the category or subcategory. *See Lignite Energy Council v. EPA, 198 F. 3d 930, 933 (D.C. Cir. 1999)* ("EPA is not required by law to subcategorize--section 111[b][2] merely states that the Administrator *may* distinguish among classes, types, and sizes within categories of new sources'" (emphasis original)); *See* also CAA section 112(d)(1) (containing almost identical language to CAA section 111, CAA section 112(d)(1) provides that "the Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing [] standards * * *"). Even if we determine that emissions characteristics are different for units that differ in class, type, or size, the Agency may still decline to subcategorize if there are compelling policy justifications that suggest subcategorization is not appropriate. *Id.*

When developing the proposed rule, we examined the EGUs in the top performing 12 percent of sources for Hg emissions. We determined that:

There were no EGUs designed to burn a non-agglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in an EGU with a height-to-depth ratio of 3.82 or greater among the top performing 12

percent of sources for Hg emissions, indicating a difference in the emissions for this HAP from these types of units. The boiler of a coal-fired EGU designed to burn coal with that heat value is bigger than a boiler designed to burn coals with higher heat values to account for the larger volume of coal that must be combusted to generate the desired level of electricity. Because the emissions of Hg are different between these two subcategories, we are proposing to establish different Hg emission limits for the two coal-fired subcategories. For all other HAP from these two subcategories of coal-fired units, the data did not show any difference in the level of the HAP emissions and, therefore, we have determined that it is not reasonable to establish separate emissions limits for the other HAP. *76 FR 25036-67.*

Based on this determination, we proposed to establish two subcategories with separate Hg limits. Comments on the proposed rule indicate that we correctly identified the EGUs that should be included in each subcategory, but the comments also demonstrated that we made certain incorrect conclusions that require us to revise the definitions of our coal-fired EGU subcategories. The revised definitions ensure that the EGUs we identified at proposal as having different Hg emissions remain in one subcategory.

As stated above, we believed at proposal that the boiler size was the cause of the different Hg emissions characteristics that led us to propose subcategorization, but many commenters indicated that it was not the boiler size but the fact that the EGUs burned a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) (low rank virgin coal) that causes

the disparity in Hg emissions. Several commenters indicated that their EGUs were designed to burn and burned low rank virgin coal but the units did not meet the height-to-depth ratio that EPA proposed. For example, the height-to-depth ratio of certain EGUs in this subcategory is in fact 3.5, not 3.82. Further, there are other EGUs in this subcategory that are circulating fluidized bed (CFB) combustion units which do not meet the height-to-depth ratio parameters in the proposed rule, nor are they anything like the pulverized coal (PC) EGUs we initially identified as having the 3.82 height-to-depth ratio.

In addition to the comments concerning EGUs firing this coal, we received comments from at least two commenters indicating that the EPA should clarify in which subcategory a unit belongs when it does not burn low rank virgin coal but is designed to combust low rank virgin coal and has a height-to-depth ratio of greater than 3.82. Commenters also indicated that CFB units that are burning coal-refuse[311] or other nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or greater are "designed to burn" any type of coal. Owners of CFB units that are not firing low rank virgin coal asked which subcategory they belong to based on their ability to burn any type of coal (including low rank virgin coal) without modification. These commenters also indicated that some coal refuse that is combusted has a heating value less than 8,300 Btu/lb but is not "virgin coal." It was unclear to which subcategory they belonged since the proposed

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[311] It is our understanding that no unit combusts coal-refuse from nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb).

rule did not in fact require the unit to burn any specific coal, instead only requiring the unit be "designed" to burn lower Btu coal.

Based on the comments received, we reevaluated the subcategory definitions because we were concerned that the definitions we proposed would improperly categorize a number of the EGUs in both subcategories. We concluded that we should not maintain the proposed definition for "[u]nits designed for coal < 8,300 Btu/lb" and exclude the CFB units and PC EGUs with a height-to-depth ratio less than 3.82 that combusted low rank virgin coal.

We were equally concerned that the subcategory definitions not be revised in a manner that would move EGUs that we believed the data show could comply with a more stringent standard into a subcategory with a less stringent standard because, aside from the type of EGUs we identified, all other classes, types, and sizes of EGUs were represented among the top performing 12 percent for Hg in the >/=8,300 Btu/lb subcategory. We were particularly concerned about the CFB units because other CFB units are well represented among the best performing EGUs for Hg in the >/=8,300 Btu/lb subcategory, but the CFB units burning low rank virgin coal are not achieving the same levels of Hg emissions control. Including the best performing CFB units from the other subcategory in the low rank virgin coal subcategory would likely lead to a Hg standard as stringent as the standard for EGUs in the >/=8,300 Btu/lb subcategory because the CFB units from the other subcategory would be used to establish the floor. We believe that result would be inconsistent with the intent of the proposed rule. We were also concerned about the information that some EGUs that fired low

rank virgin coal had a height-to-depth ratio of 3.5, not 3.82, and that some EGUs that fired other ranks of coal had a height-to-depth ratio greater than 3.82. For these reasons, we did not revise the definition to include CFB units and PC EGUs with a height-to-depth ratio greater than 3.5.

After fully considering the available information, including the comments received, we have concluded that it is appropriate to continue to base the subcategory definitions, at least in part, on whether the EGUs were designed to burn and, in fact, did burn low rank-virgin coal, but that it is not appropriate to continue to use the height-to-depth ratio criteria because that approach would potentially exclude EGUs we identified as having different Hg emission characteristics and include EGUs that did not have different emissions characteristics. We recognize that some commenters have taken the position that it is unlawful to subcategorize based on factors such as fuel type but nothing in the statute prohibits such an approach and the case law supports this approach to the extent courts have considered subcategorization based on such factors. *See Sierra Club v. Costle, 657 F 2d 298, 318-19 (D.C. Cir. 1981)* (differing pollutant content of input material can justify a different standard based on subcategorization authority to "distinguish among classes, types and sizes within categories of new sources"). Furthermore, we believe had Congress intended to prohibit the EPA from subcategorizing based on an EGU being designed to use and using a certain material input (*e.g.,* fuel) it would have clearly stated such intent in the CAA. However, we believe the Agency could decline to exercise its discretion to subcategorize even if the potential result would be the prohibition of the use of some materials if the circumstances warranted. We

note that even if we did not subcategorize on the final basis selected, the Hg emissions standard of 1.2E0 lb/Tbtu for the "unit designed for coal >/=8,300 Btu/lb" would remain the same.

We considered basing the subcategory solely on an EGU being designed to burn and burning low rank virgin coal. We decided not to do so because we were concerned that such a definition would allow sources to potentially meet the definition by combusting very small amounts of low rank virgin coal. For example, an EGU on the east coast (or any other region) that was not designed to burn and did not routinely burn low rank virgin coal could import one truck full of low rank virgin coal and burn a very small quantity of it periodically to meet the subcategory definition. To avoid creating this potential loophole, we considered other characteristics that would distinguish EGUs combusting low rank virgin coal.

We determined that these EGUs are universally constructed "at or near" a mine containing low rank virgin coal because it is not cost-effective to transport large quantities of such fuel long distances. Furthermore, we believe that this subcategory of EGUs are almost always built at a mine and limited transportation of the coal is only required as the mine face moves over the course of time. Many such EGUs construct dedicated rail lines, private roads, or conveyor systems to transport the coal to the EGU as the mine face moves. We obtained information from data acquired to develop the CSAPR indicating that the longest distance any EGU firing low rank virgin coal transports that coal is 40 miles. We believe that this distance is near the outer limits for the transport of such coal, but, even for those EGUs, the EGUs were constructed closer to a now idle mine or closer to the

working face of a mine that has now expanded away from the EGU site. For these reasons, we are including a requirement that the unit be constructed and operated at or near a mine containing the low rank virgin coal it burns.

We are revising the coal-fired EGU subcategory definitions as set out in 40 CFR 63.10042.

We believe the revised subcategory definitions are reasonable for all the reasons set forth above. The revised definitions maintain the EGUs we identified as having different Hg emissions characteristics in one subcategory and the definitions prevent other EGUs that are not firing low rank virgin coal from being required to comply only with the less stringent Hg emission standard.

As discussed in response to comments, we do not believe that additional subcategorization of other coal-fired EGUs is reasonable or appropriate. All other coal-fired EGUs that are not designed to burn and are burning low rank virgin coal are represented among the best performing sources for Hg, such that no argument exists to support that the Hg emissions from those EGUs are different. In any case, even if emissions are somewhat different as some commenters suggest, we would decline to exercise our discretion because the data demonstrate that the best performing EGUs designed to burn and burning all other ranks of coal are able to achieve the MACT level of control using currently available controls and other HAP emission reduction mechanisms (*e.g.*, coal washing) for the >/=8,300 Btu/lb subcategory.

A second issue related to subcategorization concerns non-continental liquid oil-fired EGUs. At proposal, the EPA did not have sufficient emissions data from non-

continental liquid oil-fired EGUs upon which to base a subcategory and took comment on the issue. The data have since been provided in response to the ICR and we received comments suggesting that a non-continental subcategory is appropriate based on the location of such units, the limited availability of alternative fuel sources, and the fact that the emissions characteristics of such units are distinct from continental liquid oil-fired EGUs. The EPA has evaluated the data and comments and we agree that a subcategory is warranted based for the reasons suggested by the commenters. Therefore, the Agency is finalizing the liquid oil-fired EGU subcategories of "continental" and "non-continental."

Lastly, the EPA did not have sufficient information on limited-use liquid oil-fired EGUs upon which to base a subcategory at proposal because some sources required to test under the ICR did not submit the data until after proposal. We took comment on whether a limited-use subcategory was warranted. Commenters indicated that their units were a different class and type of units because many of them were only called to service to address reliability issues associated with, for example, natural gas curtailments. The commenters further indicated that their units are different because of the generally infrequent use and the sporadic, and at times frequent, start-up and shutdown periods (*e.g.*, they are often only required to run for a couple of hours). These factors would lead to differences in the emissions characteristics for these units such that a numeric standard based on base load units would not likely be achievable during the very limited times that these limited use oil-fired units operate. Based on comments received and our own analysis, we are finalizing a subcategory for limited-use liquid oil-fired

EGUs as discussed further elsewhere in this preamble.

C. Emission Limits

The proposed rule included numerical emission limits for PM, Hg, HCl, HF, SO_2, total HAP metals, and individual HAP metals, depending on the subcategory and specific situation. These proposed limits resulted from calculations of MACT floors using information and data available to the Agency prior to proposal, as required by CAA section 112. Based on information and data received during the comment period, we have made data and calculation corrections where necessary and then re-ranked the best performing units in the MACT floor pools. Based on the new ranking, a limited number of the emission limits in the final rule have changed from those proposed.

In addition to adjustments to the emission limits themselves, we are finalizing several other changes to the emission standards that will simplify and improve compliance for sources without compromising the toxics reductions achieved. One key change, as discussed elsewhere in this notice, is that we have changed the surrogate for non-mercury metallic HAP from total particulate matter (PM) to filterable PM for coal-fired and solid oil-derived EGUs. This change is based on information provided in comments and our own conclusion that measurement of filterable PM provided assurance of equivalent HAP emissions control. Most of the non-mercury metal HAP, for which PM is a surrogate, are filterable PM and the one that is not (Se) is well controlled by the limit on acid gases. Using filterable PM as the surrogate will allow us to use continuous PM monitoring systems, which

measure filterable (but not total) PM, thereby providing a more continuous measure of compliance.

For liquid oil-fired EGUs, based on comments received and corrections made to the data submitted, we have added a filterable PM limit in the final rule as an alternative equivalent standard for the total metal-HAP limit in the proposed rule. In addition, as discussed elsewhere in this notice, we have added measurement of the moisture content of the oil (with a 1 percent limit) as an alternate compliance assurance measure for liquid oil-fired EGUs for determining compliance with the HCl and HF limits. Direct measurement of HCl and HF remains a compliance demonstration method in the final rule. Finally, as discussed in section VI.D of this notice, the final work practice standard consisting of burner tune-ups, much like those required for organic HAP control, for those limited-use liquid oil-fired EGUs whose annual capacity factor is less than 8 percent.

D. Work Practice Standards for Organic HAP Emissions

As noted earlier in section V.D., the final rule includes a work practice standard for organic HAP, including dioxins and furans, applicable to all EGUs. As noted in section V.D. above, the majority of emissions of these pollutants are below the detection levels of EPA test methods and, therefore, are impractical to measure. The work practice standard, described below, is a practical approach to ensuring that equipment is maintained and run so as to minimize emissions of dioxins and furans, and we expect it to be more effective than establishing a numeric standard that cannot reliably be measured or monitored. The work practice also applies to the

limited-use liquid oil-fired subcategory included in the final rule.

The work practice involves maintaining and inspecting the burners and associated combustion controls (as applicable), tuning the specific burner type to optimize combustion, obtaining and recording CO and NO_x values before and after the burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. In Table 3 of the final regulation, we have clarified that this refers to performance tune-ups, not tests, and have addressed the frequency requirement as discussed in response to comments about the appropriateness of the 18-month frequency. The provisions of 40 CFR 63.10006(h)(i) refer to 40 CFR 63.10021(e) for the specific steps required to be part of the periodic tune-up. We have also adjusted the language in the final rule to recognize the value of automated boiler optimization tools such as neural network systems.

Under the final rule, the tune-up must be conducted at each planned major outage and in no event less frequently than every 36 calendar months, with an exception that if the unit employs a neural-network system for combustion optimization during hours of normal unit operation, the required frequency is a minimum of once every 4 years (48 calendar months). Initial compliance with the work practice standard of maintaining burners must occur within 180 days of the compliance date of the rule. The initial compliance demonstration for the work practice standard of conducting a tune-up may occur prior to the compliance date of the rule, but must occur no later than 42 months (36 months plus 180 days) from the compliance date of the rule or, in the case of units

employing neural network combustion controls, 54 months (48 months plus 180 days). If the tune-up occurs prior to the compliance date of the rule, you must maintain adequate records to show that the tune-up met the requirements of this standard.

We have made a number of specific changes to address what to do for repairs that may require longer term corrective actions, additional methods for evaluating combustion effectiveness, and clarification on procedures for recording CO and NO_x information. There were specific comments that opposed the reference to manufacturer specifications, if available. We retained this language in the final rule, but note that these specifications apply only to the extent applicable. Specifically, if manufacturer specifications only address equipment or conditions that are no longer present given current boiler operations, then those specifications are not applicable and other combustion engineering best practice procedures for that burner type would apply. We have also clarified that portable emission monitoring equipment may be used to collect the required emissions optimization data regarding pre- and post-tune-up CO and NO_x emission levels.

E. Requirements During Startup, Shutdown, and Malfunction

We proposed numerical emission standards that would apply at all times, including during periods of startup, shutdown, and malfunction. Although at proposal we stated that we were not setting a different standard for startup and shutdown, we did propose different standards for startup and shutdown by our inclusion of the default values described below, which applied only during startup and shutdown. Specifically, we stated:

To appropriately determine emissions during startup and shutdown and account for those emissions in assessing compliance with the proposed emission standards, we propose use of a default diluent value of 10.0 percent O[2] or the corresponding fuel specific CO[2] concentration for calculating emissions in units of lb/MMBtu or lb/TBtu during startup or shutdown periods. For calculating emissions in units of lb/MWh or lb/GWh, we propose source owners use an electrical production rate of 5 percent of rated capacity during periods of startup or shutdown. We recognize that there are other approaches for determining emissions during periods of startup and shutdown, and we request comment on those approaches. We further solicit comment on the proposed approach described above and whether the values we are proposing are appropriate.

We proposed application of the respective emission limits during periods of startup and shutdown and use of default values to calculate the emission limits. The standards that apply at all times other than startup and shutdown are production-based limits, which is why we proposed the default values. The default values were meant to account for the fact that during startup and shutdown events, production (in this case the generation of electricity) is by definition nonexistent. Thus, in effect, we proposed a separate standard to apply during startup and shutdown.

We received a variety of comments on the proposed standards that would apply during startup and shutdown. Many commenters pointed to the lack of data in the record concerning emissions that occur during periods of startup and shutdown. They further asserted that emissions during these periods can be highly variable in light of the sequence of events that

occurs during the startup and shutdown of an EGU. Although a number of commenters supported the use of the diluent factor approach, including the default 5 percent of rated capacity, during startup/shutdown periods, other commenters questioned the feasibility of collecting additional data during such periods and had concerns regarding the reliability of measurements obtained from EGUs during such periods.

In response to the Agency's ICR to the utility industry, seven owners or operators indicated that they provided startup and shutdown data for their EGUs. These data were submitted in response to the requirement in the ICR to provide all available data from the 5 years prior to the date the ICR was issued. Of these data, there were almost no HAP data for startup and shutdown periods and almost all of the data failed to meet our data quality requirements.[312]

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[312] In response to the ICR, we also received SO_2 CEMS data and the Agency had additional SO_2 CEMS data available through the CAMD ARP database. We are not able to identify specific periods of start-up and shutdown in either the ICR CEMS data or the CAMD ARP data, and the ICR respondents do not indicate that the ICR data includes periods of startup and shutdown. We set the emission limits for $SO_2$and HCl using the data provided to the EPA from the 2010 ICR, not the CAMD data, since those data were taken concurrently under the same specified operating conditions using the same fuel. We used the SO_2CEMS data that was submitted in response to the ICR by converting it to single point data to correlate to the data from units that did not provide CEMS data from the relevant testing period. The emissions limits for the NESHAP incorporated variability by applying the 99 percent UPL to the average emissions developed from the stack test data and SO_2 CEMS data that was converted to stack test data. Thus, we did not have data on which to establish an SO_2 standard during periods of startup and shutdown and the numeric standards do not apply to those periods in the final rule. In contrast, the NSPS for SO_2 is applicable during periods of startup and shutdown since the long term CAMD ARP CEMS

Thus, we do not have sufficient data on emissions that occur during startup and shutdown on which to set emission standards. We are therefore establishing work practice standards rather than numeric emissions standards for periods of startup and shutdown in the final rule. Before we describe those work practices, we first address what constitutes startup and shutdown.

Several commenters had an expansive view of what constitutes startup and shutdown. We disagree with these commenters that asserted that periods of "load swings" should be considered "startup" or "shutdown," as they are generally routine, normal operations with production (*i.e.*, generation of electricity) taking place. We maintain that the standards as promulgated account for any variability in emissions that may occur during these periods over a 30-day averaging period, and commenters have provided no data that cause us to doubt that determination. We have included definitions of startup and shutdown in the final rule that are consistent with the definitions in the proposed rule. At proposal, we defined startup as the setting in operation of an affected source or portion of an affected source for any purpose, and shutdown as the cessation of operation of an affected source or portion of an affected source for any purpose.

Commenters sought more clarity regarding the meaning of these terms as applied to EGUs, so we are

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data were used to determine the average performance of the best demonstrated technology. Those long term data were assumed to incorporate process variability including that associated with fuel and process/operational changes and periods of startup and shutdown.

revising the definitions in the final rule as set out in 40 CFR 63.10042.

These interpretations are tailored for EGUs and are consistent with the definitions of "startup" and "shutdown" contained in the 40 CFR part 63, subpart A General Provisions. We believe these revised definitions address the comments and are rational based on the fact that EGUs function to provide electricity primarily for sale to the grid but also at times for use on-site; therefore, EGUs should be considered to be operating normally at all times electricity is generated. We further believe these revised definitions address what some commenters describe as "warm" and "hot" startups as long as the EGU is shutdown (*i.e.*, no fuel fired and no electricity generation) prior to the "warm" or "hot" startup period.

As for the work practices, in this final rule, the EPA is requiring sources to operate using either natural gas or distillate oil for ignition during startup. The EPA also is requiring sources to vent emissions to the main stack(s) and operate all control devices necessary to meet the normal operating standards under this final rule (with the exception of dry scrubbers and SCRs) when coal, solid oil-derived fuel, or residual oil is fired in the boiler during startup or shutdown. It is the responsibility of the operators of EGUs to start their dry scrubber and SCR systems appropriately to comply with relevant standards applicable during normal operation.

The EPA carefully considered fuels and potential operational constraints of air pollution control devices (APCDs) when designing its work practices for periods of startup and shutdown. The EPA notes that there is no technical barrier to burning natural gas or distillate oil for longer portions of startup or shutdown

periods, if needed, at a boiler, and the HAP emission reduction benefits warrant additional utilization of such fuels until the temperature and stack emissions pressure is sufficient to engage the APCDs. The EPA is aware that SCR systems with ammonia injection need to be operated within a prescribed and relatively narrow temperature window to provide NO_x reductions. Further, the EPA is aware that dry scrubbers also need to be operated close to flue gas saturation temperature. Because these devices have specific temperature requirements for proper operation, the EPA notes in its work practices that it is the responsibility of the operators of EGUs to start their SCR and dry scrubber systems appropriately to comply with relevant standards applicable during normal operation.

Some commenters have asserted that firing of fuel oil during periods of startup and shutdown constrains operation of PM controls (ESPs and baghouses) because under cooler conditions, acids and tars can condense on surfaces in these controls. The commenters assert that such condensation can cause detrimental impacts on hardware and operation of these controls, and could cause safety concerns. The EPA understands that concerns with acidic and tarry deposits are related to firing of heavy (residual) oil and hot distillate oil. Accordingly, with residual fuel oil firing, site-specific flue gas temperature and oxygen (O_2) concentration thresholds may be applicable to minimize condensation of acids and tars and thereby minimize any potential for detrimental impacts on hardware and any safety concerns. However, the EPA notes that its work practice requirements provide flexibility to the operator to take appropriate site-specific remedial measures, if needed. The EPA further notes that boilers have several options to

prevent detrimental impacts by: (1) Using startup fuels, natural gas or distillate oil, until appropriate flue gas conditions have been reached and then fire residual oil; (2) pre-coating the PM control surfaces[313] with an alkaline powder (*e.g.*, limestone); (3) installing chemically resistant bags[314] in baghouses if applicable; and (4) using low-sulfur oils. The EPA also notes that currently the industry has many operational residual oil-fired boilers that are started up with either natural gas or distillate fuel oil. At these boilers, the transition from the startup fuel, distillate oil or natural gas, to residual oil is already being practiced without unacceptable impacts on APCDs including PM controls, which are operated to meet applicable opacity limits. Based on this experience and the options described above, those boilers where residual oil is used for either a part of the startup period, or as the main fuel, will also be able to operate their PM controls to meet the work practice requirements of the rule. Note that coal firing is done at high enough temperatures that concerns with condensation are not relevant. None of the commenters have specifically commented on this aspect of coal firing.

The EPA is not aware of any operational constraints applicable to operation of wet scrubbers during startup that could cause detrimental impacts on wet scrubber hardware and safety concerns and none of the commenters have commented on this aspect of wet scrubber operation.

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[313] Coal Power, May 1, 2007: *http://www.coal powermag.com/plant_design/Coal-Plant-O-and-M-River-Locks-and-Barges-Are-an-Aging-Workforce-Too 36.html.*

[314] Neundorfer: Lesson #r, p.4-7, Table 4-1: *http://www.neundorfer.com/FileUploads/CMSFiles/Fabric%20Filter%2OMaterial [0].pdf.*

Finally, the EPA notes that dry sorbent injection (DSI) can be applied across a very broad temperature range and will be engaged when residual oil or coal is fired in a boiler to comply with HCl requirements. Again, no comments have been received on this aspect of DSI operation.

This final rule requires work practice standards for emissions during startup and shutdown, and the rule requires sources to measure and report their emissions at all times, including periods of startup and shutdown, when continuous monitoring is used to demonstrate compliance. Data collected under this final rule will provide the EPA with information to more fully analyze this issue and address it during the 8-year review established under CAA section 112.

We now address malfunctions. In contrast to the exclusion of startup and shutdown period emissions from 30-boiler operating day rolling average emissions, the final rule requires inclusion of emissions during periods of source or APCD malfunction. We have concluded that when combined with the availability of an affirmative defense as described below, this is an appropriate and practical approach.

As mentioned earlier, periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *" (*40 CFR 63.2*). The EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards. Under CAA section 112, emissions standards

for new sources must be no less stringent than the level "achieved" by the best controlled similar source and for existing sources generally must be no less stringent than the average emission limitation "achieved" by the best performing 12 percent of sources in the category. There is nothing in CAA section 112 that directs the Agency to consider malfunctions in determining the level "achieved" by the best performing or best controlled sources when setting emission standards. Moreover, while the EPA accounts for variability in setting emissions standards consistent with the CAA section 112 case law, nothing in that case law requires the Agency to consider malfunctions as part of that analysis. Clean Air Act section 112 uses the concept of "best controlled" and "best performing" unit in defining the level of stringency that CAA section 112 performance standards must meet. Applying the concept of "best controlled" or "best performing" to a unit that is malfunctioning presents significant difficulties, as malfunctions are sudden and unexpected events.

Further, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not "reasonably" foreseeable. *See, e.g., Sierra Club v. EPA, 167 F. 3d 658, 662 (D.C. Cir. 1999)* (The EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency's decision to proceed on the basis of imperfect scientific information, rather than to "invest the resources to conduct the perfect study."). *See also, Weyerhaeuser v.*

Costle, 590 F.2d 1011, 1058 (D.C. Cir. 1978) ("In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation."). In addition, the goal of a best controlled or best performing source is to operate in such a way as to avoid malfunctions of the source and accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. The EPA's approach to malfunctions is consistent with CAA section 112, and we believe it is a reasonable interpretation of the statute. This approach to malfunctions has been used consistently in CAA section 112 and CAA section 129 rulemaking actions since the D.C. Circuit's decision in *Sierra Club v. EPA, 551 F.3d 1019 (D.C. Cir. 2008)* vacated the SSM exemption contained in CFR 63.6(f)(1) and *40 CFR 63.6(h)(1)*. (*See, e.g.*, National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants, *75 FR 54970* (September 9, 2010); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units; Final Rule, *76 FR 15372* (March 21, 2011).

In the event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things,

the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or careless operation." *40 CFR 63.2* (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g.*, State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). The EPA is therefore adding to the final rule an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. *See* 40 CFR 63.10042 (defining "affirmative defense" to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also have added other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in 63.10001. (*See 40 CFR 22.24*). The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow

definition of malfunction in *40 CFR 63.2* (*i.e.*, sudden, infrequent, not reasonable preventable and not caused by poor maintenance and or careless operation). For example, to assert the affirmative defense successfully, the source must prove by a preponderance of the evidence that excess emissions "[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *" The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with section 63.10001 and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that "[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *" and that "[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *" In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with CAA section 113 (*See* also *40 CFR 22.27*).

The EPA is including an affirmative defense in the final rule as we have in other recent MACT rules so as to balance the tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source. The EPA must establish emission standards that "limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis." *42 U.S.C.*

7602(k) (defining "emission limitation and emission standard"). *See* generally *Sierra Club v. EPA, 551 F.3d 1019, 1021 (D.C. Cir. 2008).* Thus, the EPA is required to ensure that section 112 emissions limitations are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission limitation is still enforceable through injunctive relief. While "continuous" limitations, on the one hand, are required, there is also case law indicating that in some situations it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical v. Ruckelshaus, 486 F.2d 427, 433 (D.C. Cir. 1973),* the D.C. Circuit acknowledged that in setting standards under CAA section 111 "variant provisions" such as provisions allowing for upsets during startup, shutdown and equipment malfunction "appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the never to be exceeded' standard currently in force." *See* also, *Portland Cement Association v. Ruckelshaus, 486 F.2d 375 (D.C. Cir. 1973).* Though intervening case law such as *Sierra Club* v. *EPA* and the CAA 1977 amendments calls into question the relevance of these cases today, they support the EPA's view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for excess emissions that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating "upsets beyond the control of the permit holder." *Marathon Oil Co. v. EPA, 564 F.2d 1253, 1272-73 (9th Cir. 1977).* But *see, Weyerhaeuser Co. v.*

Costle, 590 F.2d 1011, 1057-58 (D.C. Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to ensure both that its emission limitations are "continuous" as required by *42 U.S.C. 7602(k)*, and account for unplanned upsets and thus support the reasonableness of the standard as a whole.

F. Testing and Initial Compliance

We have carefully evaluated the wide-ranging comments on testing, continuous monitoring, and other provisions regarding initial compliance demonstrations, and we have made adjustments intended to help streamline implementation while still ensuring adequate demonstration of compliance with the emission limits and other standards established under this final rule. The significant changes include:

1. No Fuel Analysis Requirements

Apart from an alternative that allows you to analyze fuel moisture for liquid oil-fired EGUs rather than measuring HCl and HF, the final rule does not include any of the fuel analysis requirements that were in the proposed rule, either as part of initial compliance demonstrations or ongoing compliance demonstrations. In reviewing the results of the fuel analyses and the expected range of results that would be received from laboratories conducting the proposed analyses, we determined that too many results would be returned as "below detection level" and, thus, provide little information to assist with rule implementation and compliance oversight. Given the costs and efforts involved, we determined that the proposed fuel analysis requirements would not be an effective compliance monitoring tool for this final rule.

2. Clarification of Testing

We have clarified that where options for emission limits apply (such as filterable PM versus non-mercury HAP metals, or SO_2 versus HCl), you need only perform stack testing to demonstrate compliance with the selected emission limit. For example, if you elect to meet the individual non- mercury HAP metals standards, you must conduct the Method 29 test for the metals, and you do not have to conduct a Method 5 test for PM.

3. Low Emitting EGU Qualification

We have significantly modified the proposed requirements to qualify as a LEE unit for a pollutant other than Hg based on an initial performance test. Under the proposed rule, the operating limit monitoring provided additional assurance of compliance for a source qualified for non-mercury LEE status based on an initial compliance demonstration. Under the final rule, to qualify for LEE status for pollutants other than Hg, a unit must meet the LEE criteria for a series of performance tests over a 3-year period to demonstrate that the unit continues to perform well below the standard for which the source has obtained LEE status.

G. Continuous Compliance

The most significant changes to the testing and monitoring requirements involve the procedures for demonstrating continuous compliance. The proposed rule contained different options involving CEMS, periodic stack tests, fuel analysis, and various PM and control device operating limits. The final rule greatly simplifies the requirements and provides two basic approaches for most situations: use of continuous

monitoring (either CEMS or PM continuous parametric monitoring system, CPMS) or periodic quarterly testing. The final rule does not contain the proposed fuel analysis requirements. For periodic testing, the proposed rule required testing every month or every 2 months. For those EGU owners or operators who choose to use emissions testing to demonstrate compliance, the final rule requires quarterly filterable PM or non-mercury metals HAP, whether individual or total metals, testing for coal- and liquid oil-fired units. The rule requires quarterly HCl testing for coal-fired units and quarterly HCl and HF testing, along with site-specific monitoring for liquid oil-fired units to ensure compliance with the HCl and HF standards. The final rule also has a separate compliance demonstration for those liquid oil-fired EGUs that have an annual capacity factor of less than 8 percent (emission limits do not apply, just the tune-up work practice standard). For those EGU owners or operators who choose to use emissions testing to demonstrate compliance, the final rule requires quarterly filterable PM or non-mercury metals HAP, whether individual or total metals, testing for coal- and liquid oil- fired units; quarterly HCl testing for coal-fired units and quarterly HCl and HF testing, along with site-specific parameter monitoring for liquid oil-fired units to ensure compliance with the HCl and HF standards.

The continuous monitoring options remain generally intact from the proposed rule, with relatively minor clarifications concerning calculation of 30-boiler operating day averages and QA requirements.

The final rule eliminates all operating limits for PM except for the use of a PM CPMS. For the PM CPMS, the final rule clarifies procedures for setting this

operating limit and how it is distinct from the PM emission limit. The PM CPMS will not be correlated as a PM CEMS under PS 11 and will produce data in terms of a signal you define. That signal could be milliamps, stack concentration, or other output signal instead of PM emissions in units of the standard. The operating limit will be set using the highest hourly average obtained from the PM CPMS during the performance test. Compliance with the limit is based on a 30-boiler operating day rolling average basis. However, the final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach. The EPA believes that some sources may be interested in adopting this direct approach, and so has included that option in the final rule. If this approach is selected, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of the QA requirements in PS 11 and Procedure 2. To use this option, the source must elect to meet the filterable PM standard, and not one of the HAP metals standards.

Apart from the operating limit for site-specific monitoring associated with liquid oil-fired EGUs, we removed the other operating limits for control devices based on a review of the comments, after considering other programs in place to ensure proper operations of controls at EGUs. Those other programs include compliance assurance monitoring under part 64, part 70, and New Source Review permit conditions, and other SIP and NSPS requirements for operating and maintaining equipment in accordance with good air pollution control practices. Those requirements, in combination with the CEMS, PM CPMS, and frequent periodic testing provisions under the final rule, will

enhance the monitoring of continuous compliance with the requirements of this rule.

Because the EPA is concerned that there will be little or no monitoring in these underlying applicable requirements for acid gases at liquid oil-fired EGUs, the final rule requires a site-specific monitoring plan for those units in this subcategory that demonstrate compliance with the HCl and HF standards through quarterly performance tests. With the exception for limited-use liquid oil-fired EGUs and other monitoring options available (such as fuel moisture monitoring or HCl/HF CEMS), the EPA believes this provision will apply to few units. The owner or operator will submit the site-specific plan to identify appropriate parameters that ensure that the operations of the unit critical to meeting the HCl/HF emission limits remain consistent with conditions during performance testing. This will be approved similarly to an alternative monitoring request. The plan should include the parameters, monitoring approach, QA/QC elements, and data reduction (including averaging period) elements. Like the PM CPMS operating limit, the operating limit for acid gas control devices on liquid oil-fired EGUs will be set using the highest hourly average obtained during the HCl and HF performance tests. Compliance with the limit is based on a 30-boiler operating day rolling average basis.

Finally, we have changed the continuous compliance requirements for the performance tune-up work practice standard since the proposal. Our intent was that this work practice standard could be performed in conjunction with routine maintenance operations at a facility and be a logical extension of routine best practices for boiler inspection and optimization. Based on the comments received, we have reduced the

required frequency for this inspection to every 3 years and provided incentives for neural network combustion management and optimization practices by providing a longer interval of 4 years between inspections when such systems are in use at a given EGU.

H. Emissions Averaging

We are finalizing that owners and operators of existing affected sources may demonstrate compliance by emissions averaging for existing EGUs that are located at the same facility that are within a single subcategory and that rely on emissions testing as the compliance demonstration method. In response to our request for comments on the suitability of emissions averaging and need for a discount factor, we received a range of suggestions, including requests for clarification regarding eligibility, points for and against the need for a discount factor, and suggestions to ease implementation.

As we noted at proposal, part of the EPA's general policy of encouraging the use of flexible compliance approaches where they can be properly monitored and enforced is to include emissions averaging. Emissions averaging can provide sources the flexibility to comply in the least costly manner while still maintaining a regulation that is workable and enforceable. Emissions averaging would not be applicable to new affected sources and could only be used between EGUs in the same subcategory at a particular facility. Also, owners or operators of existing sources subject to the EGU NSPS (40 CFR part 60, subparts D and Da) would be required to continue to meet the PM emission standard of that NSPS regardless of whether or not they are using emissions averaging (*i.e.*, an EGU subject to 40 CFR part 60, subpart D or Da must meet

its applicable NSPS filterable PM emission limit even if it is included in a 40 CFR part 63, subpart UUUUU, emissions averaging group for filterable PM).

Emissions averaging allows owners and operators of a facility that includes existing EGUs within a subcategory to demonstrate that the source complies with the proposed emission limits by averaging the emissions from an individual affected EGU that is emitting above the proposed emission limits with other affected EGUs at the same facility that are emitting below the proposed emission limits and that are within the same subcategory. Although some commenters note that the MACT limits are low, based on the data available to the Agency, we believe that dozens of existing EGUs are achieving all of the limits and, thus, emissions averaging is a possible approach.

The final rule includes an emissions averaging compliance alternative because emissions averaging[315] represents an equivalent, more flexible, and less costly alternative to controlling certain emission points to MACT levels. We have concluded that averaging in the proposed rule could be implemented and that it would not lessen the stringency of the MACT floor limits and would provide flexibility in compliance, cost and energy savings to owners and operators. We also recognize that we must ensure that any emissions averaging option can be implemented and enforced, will be clear to sources, and most importantly, will be no less stringent than unit-by-unit implementation of the MACT floor limits.

In the final rule, the EPA is providing that sources may average emissions from existing EGUs at the

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[315] As long as required emission rates are designed to account for factors such as changes in averaging times.

same facility and within the same subcategory. Further, for Hg emissions only from existing EGUs within the same subcategory, such EGUs in an emissions averaging plan may use an alternate compliance approach consisting of a 90-boiler operating day rolling average emission limit of 1.0 lb/TBtu or 1.1E-2 lb/GWh.

In the memo entitled "The Impact of Emission Averaging Time on the Stringency of an Emission Standard" in the docket, we have illustrated why a longer-term average results in a lower limit. In essence, longer-term averages allow particularly high (or low) measurements to be averaged with many more measurements closer to the mean. This results in the highest averages from a longer-term averaging period (*e.g.*, 90 days) being lower than the highest averages in a shorter term averaging period (*e.g.*, 30 days).

We have illustrated this concept by taking Hg CEMS data and calculating rolling 30-day averages and rolling 90-day averages. The 30-day averages have greater variability and, thus, higher peaks and valleys. The 90-day average has less variability; therefore, the same unit is able to meet a tighter 90-day limit.

The EPA is providing this alternate 90-day rolling average compliance approach for Hg only. A 90-day rolling average is appropriate for Hg, and only for Hg, because the health and environmental impacts associated with Hg are related to environmental loading rather than shorter term inhalation or other acute exposure, as is the case with HCl and PM. We believe that this alternative compliance approach will provide at least the same level of environmental protection while allowing companies greater flexibility to use emissions averaging. For example, such an

approach would allow for the averaging of an infrequently operated unit that is operating slightly above the standard with a more frequently operated unit that is operating below the standard in the instances when the more frequently operated unit is in a multi-day or multi-week maintenance outage.

The EPA has concluded that it is permissible to establish within a NESHAP a unified compliance regimen that permits averaging within the same facility across individual existing EGUs subject to the same standards under certain conditions. As mentioned earlier, individual EGUs within an emissions averaging group would be allowed to have emissions greater than, less than, or equivalent with the emissions limit for their subcategory, provided that the average emissions comprised from individual EGU emissions do not exceed the emissions limit for their subcategory. Averaging across affected units is permitted only if it can be demonstrated that the total quantity of any particular HAP that may be emitted by that portion of a contiguous major source that is subject to the same standards in the NESHAP will not be greater under the averaging mechanism than it could be if each individual affected EGU in the subcategory complied separately with the applicable standard. Under this test, the practical outcome of averaging is equivalent to compliance with the MACT floor limits by each discrete EGU, and the statutory requirement that the MACT standard reflect the maximum achievable emissions reductions is, therefore, fully effectuated.

As noted in the proposal preamble, in past rulemakings, the EPA has generally imposed certain limits on the scope and nature of emissions averaging programs. These limits include: (1) No averaging between different types of pollutants; (2) No averaging

between sources that are not part of the same affected source; (3) No averaging between individual sources within a single major source if the individual sources are not subject to the same NESHAP; and (4) No averaging between existing sources and new sources.

The final rule fully satisfies each of these criteria. First, emissions averaging would only be permitted between individual existing sources at a single stationary source (*i.e.*, the facility), and would only be permitted between individual sources in the same subcategory in the final EGU NESHAP. Further, emissions averaging would not be permitted between two or more different affected sources. Finally, new affected sources could not use emissions averaging. Accordingly, we have concluded that the averaging of emissions across affected units in the same existing source subcategory is consistent with the CAA. In addition, the final rule requires each facility that intends to utilize emissions averaging to develop an emissions averaging plan, which provides additional assurance that the necessary criteria will be followed. In this emissions averaging plan, the facility must include the identification of: (1) All units in the averaging group; (2) the control technology installed; (3) the process parameter that will be monitored; (4) the specific control technology or pollution prevention measure to be used; (5) the test plan for the measurement of the HAP being averaged; and (6) the operating parameters to be monitored for each control device. A state, local, or tribal regulatory agency that is delegated authority for this rule could require the emissions averaging plan to be submitted or even approved before emissions averaging could be used. Upon receipt, the regulatory authority would not be able to approve an emissions averaging plan differing from the eligibility criteria contained in the rule.

The final rule excludes new affected sources from the emissions averaging provision. The EPA does not believe the statute authorizes emissions averaging for new affected sources. One reason we allow emissions averaging is to give existing sources flexibility to achieve compliance at diverse points with varying degrees of add-on control already in place in the most cost-effective and technically reasonable fashion.

With the monitoring and compliance provisions that are being finalized, there is additional assurance that the environmental benefit will be realized. Further, the emissions averaging provision would not apply to individual EGUs if the EGU shares a common stack with units in other subcategories, because in that circumstance it is not possible to distinguish the emissions from each individual unit.[316]

The rule allows EGUs that rely on CEMS for compliance demonstrations to be able to participate in emissions averaging and the emissions limits are not subject to a discount. The EPA believes that the data certainty provided by units that use CEMS would be ideal for emissions averaging and the flexibility and cost-effectiveness it offers. Given the homogeneity of fuels within the rules subcategories, along with other emissions averaging criteria, the Agency believes use of a discount factor to be unwarranted for this rule.

The emissions averaging provisions in this final rule are based in part on the emissions averaging provisions in the Hazardous Organic NESHAP (HON). The legal basis and rationale for the HON emissions

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[316] The EPA has reviewed monitoring data submitted to the Agency under the Title IV Acid Rain Program. Based on that review, the EPA is unaware of any coal- and oil-fired units that share a common stack.

averaging provisions were provided in the preamble to the final HON.[317] We do not believe that we have the authority to provide for emissions averaging among EGUs in different subcategories or among EGUs not physically located at the same affected facility.

I. Notification, Recordkeeping, and Reporting

Compared to the proposed rule, the reduced continuous compliance requirements in the final rule--primarily reduced testing frequencies and removal of fuel analyses and control device or fuel operating parameter monitoring--considerably reduces the overall burden associated with recordkeeping and reporting. Based on evaluation of the comments received, we have established a provision in the final rule for submission of most CEMS data (including monitoring plan, emissions data, and QA data) through ECMPS, so that the affected industry uses a common reporting tool for submitting CEMS data.

For data other than most CEMS data, the final rule requires electronic reporting of certain data, including performance test reports, PM CPMS data, PM CEMS data, and, if approved as part of an alternative monitoring request, HAP metals CEMS data. Other reports, such as notifications, must be submitted in hard copy format or in accordance with the procedures established by state and local agencies that receive delegation for implementing this rule. In the proposed rule, we took comment on these approaches and stated our anticipation of adopting these approaches. In the final rule, we have extended the ECMPS reporting to most CEMS data to promote harmonization for CEMS

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[317] Hazardous Organic NESHAP *(59 FR 19,425;* April 22, 1994).

data from the industry, while leaving reporting of non-CEMS data in a separate reporting system.

J. Technical / Editorial Corrections

In this final action, we are making a number of technical corrections and clarifications to 40 CFR part 63, subpart UUUUU. These changes clarify procedures for implementing the emission limitations for affected sources. We are also clarifying several definitions to help affected sources determine applicability of this rule. We have modified some proposed regulatory language based on public comments. In addition, in response to comments received (including the May 2010 notice from the Utility Air Regulatory Group (UARG) of calculation errors in the proposed Hg MACT floor limits), we have checked all calculations and made corrections where necessary.

In several places throughout the subpart, including the associated tables, we have corrected the cross-references to other sections and paragraphs of the subpart.

VII. Public Comments and Responses to the Proposed NESHAP

A. MACT Floor Analysis

1. New Data/Technical Corrections to Old Data

Comment: Many commenters identified errors in the emissions database compiled through information provided by industry in response to the 2010 information collection request (ICR) that supported development of this rule. Commenters submitted corrections to the EPA during the public comment period.

Response: The EPA has incorporated technical corrections and new data submitted prior to the end of the comment period. The corrections and new data are described in detail in a memorandum in the docket. The EPA re-ranked the sources in the MACT floor pools to the extent necessary based on the new or corrected data, and we recalculated the MACT floors as necessary based on the re-ranking of sources. The revised MACT floors were established using the same methodology set forth in the proposed rule.

2. Pollutant-by-Pollutant Approach

Comment: Many commenters raised concerns about the way the EPA determined the MACT floors using a pollutant-by-pollutant approach. Commenters contended that such a methodology produced limits that are not achievable in combination, and as such, the limits do not comport with the intent of the statute or the recent court decision (*NRDC* v. *EPA*, 2007). Commenters further added that the CAA directs the EPA to set standards based on the overall performance of "sources" and CAA sections 112(d)(1), (2), and (3) specify that emissions standards be established on the "in practice" performance of a "source" in the category or subcategory. Commenters stated that if Congress had intended for the EPA to establish MACT floor levels considering the achievable emission limits of individual HAP, it could have worded CAA section 112(d)(3) to refer to the best-performing sources "for each pollutant." Many commenters added that the EPA's discretion in setting standards is limited to distinguishing among classes, types, and sizes of sources. Commenters contend that although Congress limited the EPA's authority to parse units and sources with similar design and types, it does not allow the EPA to "distinguish" units and sources by individual

pollutant as proposed in this rule (*Sierra Club v. EPA, 551 F.3d 1019, 1028 (D.C. Cir. 2008)*). By calculating each MACT floor independently of the other pollutants, commenters contend that the combination of HAP limits results in a set of standards that only a hypothetical "best performing" unit could achieve.

Response: We disagree with the commenters who believe MACT floors cannot be set on a pollutant-by pollutant basis. Contrary to the commenters' suggestion, CAA section 112(d)(3) does not mandate a total facility approach. A reasonable interpretation of CAA section 112(d)(3) is that MACT floors may be established on a HAP-by-HAP basis, so that there can be different pools of best performers for each HAP. Indeed, as illustrated below, the total facility approach not only is not compelled by the statutory language but can lead to results so arbitrary that the approach may simply not be legally permissible.

Clean Air Act section 112(d)(3) is not explicit as to whether the MACT floor is to be based on the performance of an entire source or on the performance achieved in controlling particular HAP. Congress specified in CAA section 112(d)(3) the minimum level of emission reduction that could satisfy the requirement to adopt MACT. For new sources, this floor level is to be "the emission control that is achieved in practice by the best controlled similar source." For existing sources, the floor level is to be "the average emission limitation achieved by the best performing 12 percent of the existing sources" for categories and subcategories with 30 or more sources, or "the average emission limitation achieved by the best performing 5 sources" for categories and subcategories with fewer than 30 sources. Commenters point to the statute's reference

to the best performing "sources," and claim that Congress would have specifically referred to the best performing sources "for each pollutant" if it intended for the EPA to establish MACT floors separately for each HAP.

The EPA disagrees. The language of the Act does not address whether floor levels can be established HAP-by-HAP or by any other means. The reference to "sources" does not lead to the assumption the commenters make that the best performing sources can only be the best-performing sources for the entire suite of regulated HAP Instead, the language can be reasonably interpreted as referring to the source as a whole or to performance as to a particular HAP. Similarly, the reference in the new source MACT floor provision to "emission control achieved by the best controlled similar source" can mean emission control as to a particular HAP or emission control achieved by a source as a whole.

Commenters also stressed that CAA section 112(d) requires that floors be based on actual performance from real facilities. The EPA agrees that this language refers to sources' actual operation, but again the language says nothing about whether it is referring to performance as to individual HAP or to single facility's performance for all HAP. Industry commenters also said that Congress could have mandated a HAP-by-HAP result by using the phrase "for each HAP" at appropriate points in CAA section 112(d). The fact that Congress did not do so does not compel any inference that Congress was *sub-silentio* mandating a different result when it left the provision ambiguous on this issue. The argument that MACT floors set HAP-by-HAP are based on the performance of a hypothetical facility, so that the limitations are not based on those

achieved in practice, just reiterates the question of whether CAA section 112(d)(3) refers to whole facilities or individual HAP. All of the limitations in the floors in this rule reflect sources' actual performance and were achieved in practice. As to commenters' claims that standards set in this manner cannot be met by any actual sources, we have determined that there are approximately 69 existing coal-fired EGUs that meet all of the final existing source MACT emission limits (out of 252 EGUs that reported data for Hg, PM, and HCl in the 2010 ICR) and at least one EGU that meets all of the final new source MACT emission limits.

Commenters also point to the EPA's subcategorization authority, and claim that because Congress authorized the EPA to distinguish among classes, types, and sizes of units, the EPA cannot distinguish units by individual pollutant, as they allege the EPA did in the proposed rule. However, that statutory language addresses the EPA's authority to subcategorize sources within a source category prior to setting standards, which the EPA has done for certain EGUs. The EPA is not distinguishing within each subcategory based on HAP emitted. Rather, it is establishing emissions standards based on the emissions limits achieved by units in each subcategory. Therefore, the EPA's subcategorization authority is irrelevant to the question of how the EPA establishes MACT floor standards once it has made the decision to distinguish among sources and create subcategories.

The EPA's long-standing interpretation of the Act is that the existing and new source MACT floors are to be established on a HAP-by-HAP basis. One reason for this interpretation is that a whole plant approach

could yield least common denominator floors--that is, floors reflecting limited or no control, rather than performance which is the average of what best performers have achieved. *See 61 FR 173687* (April 19, 1996); *62 FR 48363-64* (September 15, 1997) (same approach adopted under the very similar language of CAA section 129(a)(2)). Such an approach would allow the performance of sources that are outside of the best-performing 12 percent for certain pollutants to be included in the floor calculations for those same pollutants, and it is even conceivable that the worst performing source for a pollutant could be considered a best performer overall, a result Congress could not have intended. Inclusion of units that are outside of the best performing 12 percent for particular pollutants would lead to emission limits that do not meet the requirements of the statute.

For example, if the best performing 12 percent of facilities for HAP metals were also the worst performing units for acid gas HAP and the best performers for acid gas HAP were the worst performers for HAP metals, the floor for acid gases or metals would end up not reflecting best performance. In such a situation, the EPA would have to make a value judgment as to which pollutant reductions were most critical to decide which sources are best controlled.[318] Such value judgments are antithetical to the direction of the statute at the MACT floor-setting stage.

Commenters suggested that a multi-pollutant approach could be implemented by weighting

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[318] See Petitioners Brief in *Medical Waste Institute et al.* v. *EPA*, No. 09-1297 (D.C. Cir.) pointing out, in this context, that "the best performers for some pollutants are the worst performers for others" (p. 34) and "[s]ome of the best performers for certain pollutants are among the worst performers for others."

pollutants according to relative toxicity and calculating weighted emissions totals to use as a basis for identifying and ranking best performers. This suggested approach would require the EPA to essentially prioritize the regulated HAP based on relative risk to human health of each pollutant, where risk is a criterion that has no place in the establishment of MACT floors, which are required by statute to be based on technology.

The central purpose of the amended air toxics provisions was to apply strict technology-based emission controls on HAP. *See, e.g.*, H. Rep. No. 952, 101st Cong. 2d sess. 338. An interpretation that the floor level of control must be limited by the performance of devices that only control some of these pollutants effectively guts the standards by including worse performers in the averaging process, whereas the EPA's interpretation promotes the evident Congressional objective of having the floor reflect the average performance of best performing sources. Because Congress has not spoken to the precise question at issue, and the Agency's interpretation effectuates statutory goals and policies in a reasonable manner, its interpretation must be upheld. *See Chevron v. NRDC, 467 U.S. 837 (1984).* n319

n319 Because industry commenters argued that the statute can only be read to allow floors to be determined on a single source basis, commenters offered no view of why their reading could be viewed as reasonable in light of the statute's goals and objectives. It is not evident how any statutory goal is promoted by an interpretation that allows floors to be determined in a manner likely to result in floors reflecting emissions from worst or mediocre performers.

The EPA notes, however, that if optimized performance for different HAP is not technologically possible due to mutually inconsistent control technologies (for example, if metals performance decreased as organics reduction is optimized), then this would have to be taken into account by the EPA in establishing a floor (or floors). The Senate Report indicates that if certain types of otherwise needed controls are mutually exclusive, the EPA is to optimize the part of the standard providing the most environmental protection. S. Rep. No. 228, 101st Cong. 1st sess. 168 (although, as noted, the bill accompanying this Report contained no floor provisions). It should be emphasized, however, that the D.C. Circuit has stated that "the fact that no plant has been shown to be able to meet all of the limitations does not demonstrate that all the limitations are not achievable." *Chemical Manufacturers Association v. EPA, 885 F. 2d at 264* (upholding technology-based standards based on best performance for each pollutant by different plants, where at least one plant met each of the limitations but no single plant met all of them).

All available data for EGUs indicate that there is no technical problem achieving the floor levels contained in this final rule for each HAP simultaneously, using the MACT floor technology. Data demonstrating a technical conflict in meeting all of the limits have not been provided, and, as stated above, based on the available data, there are approximately 64 EGUs that meet all of the final existing source emission limits and at least one EGU that meets all of the final new source emission limits.

3. Minimum Number of EGUs To Set Floors

Comment: Many commenters indicated that CAA section 112 requires that data from a minimum of 5

units are required to set MACT floors for existing sources. Commenters noted that the EPA's use of less than 5 units for subcategories with greater than 30 units is a legalistic reading of CAA section 112 that could result in such absurd results as using 5 units to set MACT floors for a subcategory with 29 units and data for only 10 units, but using a single unit to set MACT floors for a subcategory with 31 units and data for only 10 units.

Response: The EPA does not agree that CAA section 112(d)(3) mandates a minimum of 5 sources in all instances, notwithstanding the incongruity of having less data to establish floors for larger source categories than is mandated for smaller ones. The literal language of the provision appears to compel this result. CAA section 112(d)(3) states that for categories and subcategories with at least 30 sources, the MACT floor for existing sources shall be no less stringent than the average emission limitation achieved by the best-performing 12 percent of the sources for which the Administrator has emissions information. The plain language of this provision requires the use of fewer data points for large source categories than for small source categories where the Administrator only has emissions information on a small number of units for categories and subcategories with 30 or more sources. Furthermore, commenters contend that Congress could not have intended the floors for a subcategory with 29 sources to be based on 5 sources and a subcategory with 31 sources to be based on less than that number; but we maintain this contention is without merit because 12 percent of 31 is 3.72 (rounded to 4) so the EPA would not base standards for a subcategory with 31 sources on 5 sources even if we had data on all 31 sources in the subcategory. For these reasons, we decline to adopt commenters'

position and continue to adhere to the clear statutory directive.

4. Treatment of Detection Levels

Comment: Commenters stated that when setting the MACT floors, non-detect values are present in many of the datasets from best performing units. Commenters provided input on how these non-detect values should be treated in the MACT floor analysis. Some commenters agreed that it is appropriate to keep the detection levels as reported, while certain commenters suggested that the detection levels should be replaced using a value of half the method detection limit (MDL). Many other commenters stated that data that are below the detection limit should not be used in setting the floors, and these data should be replaced with a higher value including either the MDL, limit of quantitation (LOQ), practical quantitation limit (PQL), or reporting limit (RL) for the purposes of the MACT floor calculations. Other commenters stated all non-detect values should be excluded from the floor analysis, or all values should be treated as zero.

Some commenters stated it is necessary to keep the data as reported because changing values would lead to an upward bias. Additional commenters agreed with this basic premise, but suggested that replacing non-detect data with a value of half the MDL is appropriate while still minimizing the bias. They noted that treating measurements below the MDL as occurring at the MDL is statistically incorrect and violates the statute's "shall not be less stringent than" requirement for MACT floors. One commenter also provided a reference for a statistical method based on a log-normal distribution of the data which estimated the "maximum likelihood" of data values; this result is slightly higher than half the MDL.

Some commenters stated that it is necessary to substitute the MDL value when performing the MACT floor calculations. With MDL defined as the lowest concentration that can be distinguished from the blank at a defined level of statistical significance, this is an appropriate value. If MDL values are not reported, one commenter suggested an approach for estimating an MDL equivalent value, but recognized that the background laboratory and test report files may not be available to the EPA in order to derive these estimates.

Most commenters representing industry and industry trade groups argued that either LOQ or PQL values should replace non-detects. The LOQ is defined as the smallest concentration of the analyte which can be measured. These commenters contended that the LOQ leads to a quantifiable amount of the substance with an acceptable level of uncertainty. A few commenters provided calculations showing some of the proposed MACT floors were below the LOQ. Additionally, some of these commenters stated that using LOQ or PQL values also incorporates additional sources of random and inherent sampling error throughout the testing process, which is necessary. These errors occur during sample collection, sample recovery, and sample analysis; MDL values only account for method specific (*e.g.*, instrument) errors. These commenters contended that the three times the MDL approach discussed in the proposal accounts for some measurement errors but does not account for these unavoidable sampling errors. The commenters also noted that an LOQ is calculated as 3.18 times the MDL, and PQL is calculated as 5 to 10 times the MDL. Many of the commenters in support of using either an LOQ or PQL value ultimately believed a work practice is more appropriate where a MACT floor limit is below

either of these two values. They cited CAA section 112(h)(1) which allows work practices under CAA section 112(h)(2) if "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations". These commenters stated that the inability of sources to accurately measure a pollutant at the level of the MACT floor qualifies as such a technological limitation that warrants a work practice standard.

Commenters stated that where the proposed MACT floor is below the LOQ or PQL then that source category has a technological measurement limitation. A few commenters suggested RL values should be used when developing the floor limits. They stated that the RL is the lowest level at which the entire analytical system gives reliable signals and includes an acceptable calibration point. They added that use of an acceptable calibration point is critical in showing that numbers are real versus multiplying the MDL by various factors.

Several commenters stated that all non-detect values should be excluded from MACT floor calculations. They believed that excluding all non-detect values would eliminate any potential errors or accuracy issues related to testing for compliance. Due to inconsistencies of the MDL value reported for non-detect data, one commenter suggested treating all such values as zero. This would provide a consistent approach for setting the floor as well as determining compliance.

Several commenters provided input on the EPA's proposed method of three times the MDL as an option for setting limits. A few commenters in support noted that this approach provided a reasonable method to account for data variability as it took into account more than just analytical instrument precision. Many

other commenters argued that this method results in limits which are too low, namely that it is still lower than the LOQ value which they are in favor of as a substitute for any reported non-detect data. Other commenters disagreed with this method and claimed that it would lead to results which introduce a high bias in the floor setting process. A few contended that multiplying by 3 would introduce a 300 percent error into the floor, resulting in a floor that is less stringent than required by the Act. Others suggested that the MDL values are antiquated and already too high and thus it is not appropriate to multiply them by three. Also, a few commenters suggested multiplying the MDL by three would not reflect the actual lower emissions achieved by any source and as such is unlawful under CAA section 112(d).

Response: We agree with many of the comments related to treatment of data reported as detection limit values in the development of MACT floors and emissions limits. As we noted at proposal, the statistical probability procedures applied in calculating the floor or an emissions limit inherently and reasonably account for emissions data variability including measurement imprecision when the database represents multiple tests from multiple emissions units for which all of the data are measured significantly above the method detection level. That is less true when the database includes emissions occurring below method detection capabilities regardless of how those data are reported.

The EPA's guidance to respondents for reporting pollutant emissions used to support the data collection specified the criteria for determining test-specific method detection levels. Those criteria ensure that there is only about a 1 percent probability of an error

in deciding that the pollutant measured at the method detection level is present when in fact it was absent. (Reference: ReMAP: PHASE 1, Precision of Manual Stack Emission Measurements; American Society of Mechanical Engineers, Research Committee on Industrial and Municipal Waste, February 2001.) Such a probability is also called a false positive or the alpha, Type I, error. This means specifically that for a normally distributed set of measurement data, 99 out of 100 single measurements will fall within +/-2.54 x standard deviation of the true concentration. The anticipated range for the average of repeated measurements comes progressively closer to the true concentration. More precisely, the anticipated range varies inversely with the square root of the number of measurements. Thus, for a known standard deviation (SD) of anticipated single measurements, the anticipated range for 99 out of 100 future triplicate measurements will fall within +/-2.54 SD/[radical]3 of the true concentration. This relationship translates to an expected measurement imprecision for an emissions value occurring at or near the method detection level of about 40 to 50 percent.

By assuming a similar distribution of measurements across a range of values and increasing the mean value to a representative higher value (*e.g.*, 3 times minimum detection level or 3xMDL), we can estimate measurement imprecision at other levels. For an assumed 3xMDL, the estimated measurement imprecision for a three test run average value would be on the order 10 to 20 percent. This is about the same measurement imprecision as found for Methods 23 and 29 indicated in the ASME ReMAP study for the sample volumes prescribed in the final rule (*e.g.*, 4 to 6 dscm) for multiple tests.

Analytical laboratories often report a value above the method detection limit that represents the laboratory's perceived confidence in the quality of the value. This independently adjusted value is expressed differently by various laboratories and is called LOQ, PQL, or RL. In many cases, the LOQ, PQL, or RL is simply a multiplication of the method detection limit. Commonly used multipliers range from 3 to 10. Because these values reflect individual laboratories' perceived confidence, and, therefore, could be viewed as arbitrary, we decline to adopt the LOQ, PQL, or RL because such approaches in our view would inappropriately inflate the MACT floor standards. Our alternative to those inconsistent approaches is discussed below.

Consistent with findings expressed in reports of emissions measurement imprecision and the practices of analytical laboratories, we believe that using a measurement value of 3 times a representative method detection limit established in a manner that assures 99 percent confidence of a measurement above zero will produce a representative method reporting limit suitable for establishing regulatory floor values.

On the other hand, we also agree with commenters that an emissions limit set from a small subset of data or data from a single source may be significantly different than the actual method detection levels achieved by the best performing units in practice. This fact, combined with the low levels of emissions measured from many of the best performing units, led the EPA since proposal to review and revise the procedure intended to account for the contribution of measurement imprecision to data variability in establishing effective emissions limits. In response to the comments about the quality of measurements at

very low emissions limits especially for new sources, we revised the procedure for identifying a representative method detection level (RDL).

The revised procedure for determining an RDL starts with identifying all of the available reported pollutant-specific method detection levels for the best performing units regardless of any subcategory (*e.g.*, existing or new, fuel type, etc.). From that combined pool of data, we calculate the arithmetic mean value. By limiting the data set to those tests used to establish the floor or emissions limit (*i.e.*, best performers), which in this case is a larger data set than normally available for establishing NESHAP, we believe that the result is representative of the best performing testing companies and laboratories using the most sensitive analytical procedures. We believe that the outcome should minimize the effect of a test(s) with an inordinately high method detection level (*e.g.*, the sample volume was too small, the laboratory technique was insufficiently sensitive, or the procedure for determining the minimum value for reporting was other than the detection level). We then call the resulting mean of the method detection levels the representative detection level (RDL) because it is characteristic of accepted source emissions measurement performance.

The second step in the process is to calculate 3xRDL to compare with the calculated floor or emissions limit. This step is similar to what we have used for other NESHAP including the Portland Cement rule. As outlined above, we use the multiplication factor of 3 to reduce the imprecision of the analytical method until the imprecision in the field sampling reflects the relative method precision as estimated by the ASME ReMAP study. That study indicates that such relative

imprecision remains a constant 10 to 20 percent over the range of the method. For assessing the calculated floor results relative to measurement method capabilities, if 3xRDL were less than the calculated floor or emissions limit (*e.g.*, calculated from the upper predictive limit, UPL), we would conclude that measurement variability was adequately addressed with the initial floor calculation. The calculated floor or emissions limit would need no adjustment. If, on the other hand, the value equal to 3xRDL were greater than the UPL, we would conclude that the calculated floor or emissions limit did not account entirely for measurement variability. Where such was the case, we substituted the value equal to 3xRDL for the calculated floor or emissions limit (UPL) which results in a concentration where the method would produce measurement accuracy on the order of 10 to 20 percent similar to other EPA test methods and the results found in the ASME ReMAP study.

We determined the RDL for each pollutant using data from tests of all the best performers for all of the final regulatory subcategories (*i.e.*, pooled test data). We applied the same pollutant-specific RDL and emissions limit assessment and adjustment procedures to all subcategories for which we established emissions limits. We believe that adjusting emissions limits in this manner, which ensures that measurement variability is adequately addressed relative to compliance determinations, is a better procedure than the one applied at proposal, which was based on more limited data. We also believe that currently available emissions testing procedures and technologies provide the measurement certainty sufficient for sources to demonstrate compliance at the levels of the revised emissions limits.

5. Basis for New Source MACT

Comment: Several commenters stated that the proposed limits set for new EGUs do not represent the best performing EGU. The commenters state that the EPA has chosen the strictest limit irrespective of the EGU and that limits for new EGUs should be achievable. According to the commenters, no existing EGU is currently meeting the proposed limits, which will result in a moratorium on the construction of new coal-fired EGUs. Further, commenters state that another result of the EPA's flawed approach is that the proposed standards for new EGUs are so low that adequate test methodologies to demonstrate compliance do not exist. Without accurate testing methodologies, commenters assert that contractors will not guarantee that potential emission control technologies will meet the proposed standards. Without accurate test methodologies and vendor guarantees, commenters believe that financing of new facilities will be virtually impossible to secure which will, in turn, effectively preclude the construction of any new coal-based EGUs.

Commenters also stated that the EPA failed to address cumulative effects of using multiple pollution control devices in determining MACT levels applicable to PM levels. In proposing total PM as a surrogate, commenters believe that the EPA failed to consider or address the antagonistic effects that adding multiple pollution control devices can have on an EGU's HAP emissions. Commenters indicated that EGUs would not be able to comply with the proposed new source HCl limit without adding a scrubber or some type of sorbent injection to control HCl emissions. Adding these HCl control technologies will increase the total

PM emissions of these units. According to commenters, because a fabric filter-alone configuration (the basis for the new source PM limit) would not meet all MACT limits, these units may not be the best-performing units.

Response: The EPA disagrees with the commenters' statements that no existing unit is currently meeting the new source limits. The EPA established the new source limits based on data from existing EGUs and there is at least one EGU, based on the data available, that is meeting all three final HAP limits and at least eight EGUs that are meeting one or more of the new source limits. As a result of comments received on the full body of data, the EPA has re-ranked the best performing EGUs and reviewed the new source limits based on the re-ranking where appropriate. Based on the revised ranking, the best performing source for PM has changed and that source now forms the basis for the new source filterable PM limit in the final rule. The source is a coal-fired EGU that includes the entire suite of controls that would likely be required on a new coal-fired source constructed prospectively (*i.e.*, it is a unit with SCR, dry FGD, and FF). Thus, the commenters' concerns are no longer relevant as they relate to PM emissions from coal-fired EGUs.

The EPA also believes that the EGUs serving as the basis for the new source Hg and HCl limits in the final rule are representative of what a new coal-fired EGU would look like to meet all of the requisite regulations applicable to EGUs (*e.g.*, NSPS and the CSAPR) as they also include the entire suite of controls that would likely be required on a new coal-fired source constructed prospectively. The EPA has also taken into account the ability of the various test methods to accurately measure emissions at the levels being

demonstrated by the EGUs in the top performing 12 percent in establishing the final limits, and we have determined that there are adequate test methods to measure the regulated HAP at the new source levels.

6. Achievability of Limits

Comment: A number of commenters state that the EPA has chosen the strictest limit irrespective of the unit and that limits for new EGUs should be achievable. According to the commenters, no existing unit is currently meeting the proposed new source limits, which will result in a moratorium on the construction of new coal-fired units. The commenters state that this regulation goes beyond protecting public health and will impact the country's choice of fuel for energy production. Other commenters state that another result of the EPA's flawed approach is that the proposed standards for new units are so low that adequate test methodologies to demonstrate compliance do not exist. Without accurate testing methodologies, commenters allege that contractors will not guarantee that potential emission control technologies will meet the proposed standards. Without accurate test methodologies and vendor guarantees, commenters believe that financing of new facilities will be virtually impossible to secure, and that this in turn will effectively preclude the construction of any new coal-based units. Commenters maintain that adopting standards effectively banning new coal units amounts to a momentous change in national energy policy without discussion or analysis and far exceeds the EPA's authority.

Some commenters add that the proposed new source MACT standards do not represent rates that have been achieved in practice and are orders of magnitude lower than any of the CAA section 112(g) case-by-case

MACT limits established for the most advanced units in the U.S. coal fleet by multiple state agencies.

Other commenters stated that the synergistic impact of multiple controls has not been taken into account in the proposed rules. Commenters argue that circumstances exist with respect to the control of acid gases, which will require scrubbers or other SO[2] controls that add particulate to the flue gas stream, and that added particulate must be removed by PM control devices along with the particulate added to the flue gas for EGUs that need to install ACI for Hg control. Because particulate devices provide a fixed percent reduction of particulate, commenters assert that it is mathematically certain that PM performance will decrease because control of both acid gases and Hg would add PM to the flue gas stream which would in turn decrease performance of the PM control on the relevant mass metric. As a consequence, commenters allege that there is no assurance that sources can meet the EPA's "cherry-picked" floors for acid gases and for Hg by "optimizing" these systems to meet the performance of the floor units because to do so would impact their ability to meet the EPA's similarly "cherry-picked" total PM floor standard.

The commenters state that, for existing sources as with the new source standard-setting approach, a pollutant-by-pollutant approach does not consider what the top performing 12 percent achieve in practice for all pollutants and does not consider the antagonistic effects of the concurrent use of various control technologies. For example, one commenter states that 47 of the 131 sources used to calculate the existing source total PM limit only had PM control but no acid gas or Hg controls that could emit additional PM. According to the commenter, the CAA is clear that

standards must be based on actual sources and not the product of a pollutant-by-pollutant determination resulting in a set of composite standards that do not necessarily reflect the overall performance of any actual source. To address these issues, the commenter recommends that the EPA use an approach that more accurately reflects what actual best performing sources achieve.

Response: The EPA disagrees with the commenters' contention that the pollutant-by-pollutant approach to establishing MACT floors is inconsistent with the CAA for the reasons set forth in the response to comments on the EPA's MACT floor setting process. In addition, the EPA established the proposed new source limits based on data from existing EGUs, and there are EGUs that are able to meet the new source limits. To the extent the commenters are concerned that no existing source is simultaneously meeting all of the new sources limits, we note that the EPA has revised the new source standards based on comments and data corrections that industry made to data it incorrectly provided in response to the utility ICR. We have identified at least one source that is meeting all of the new source MACT limits in the final rule.

We disagree with commenters that suggest the proposed new source standards are invalid because they are more stringent than CAA section 112(g) case-by-case MACT limits established by state agencies. As commenters note, states, not the EPA, established the CAA section 112(g) standards, and they did so based on the information available to them. The EPA likewise must establish CAA section 112(d) standards based on the available data. We have considered the available data and information, including the 2010 ICR data, and complied with the requirements of CAA

section 112(d) in establishing the standards in this final rule. That the final standards are more stringent than CAA section 112(g) standards issued by certain state agencies has no bearing on the legitimacy of the standards at issue here.

The EPA agrees with commenters that the SO_2 and some Hg controls may add to the PM loading and that it is reasonable to establish the new source standard based on an EGU that has a suite of controls that will be required of any new source. For example, new coal-fired EGUs will be required to comply with the utility NSPS and may have to comply with the CSAPR and other requirements (*e.g.*, SIP or state-only requirements). Commenters are also correct that the proposed new source PM surrogate standard was based on a source that is not like a coal-fired EGU that would be constructed today (*i.e.*, an EGU with only PM control and no SO_2 controls).

The final standard is not based on the source used to establish the proposed limit. As stated above, industry commenters provided data corrections and new data and the EPA considered that new and revised data in establishing the final standards. We re-ranked all the coal-fired EGUs based on the new data. The new ranking of coal-fired EGUs resulted in a change of the source we used to establish the new source PM surrogate standard for non-mercury metal HAP. The basis for the new source limit in the final rule is a unit that has a full suite of controls similar to what would be required for any new coal-fired EGUs (*i.e.*, it is a unit with SCR, dry FGD, and FF). The EPA has identified at least one EGU meeting all of the final new source limits; thus, the EPA does not believe that it is finalizing standards that "ban" new coal-fired generation as indicated by the commenter.

The EPA also disagrees that the final new source standards are so stringent that there are not adequate test methods available to determine compliance with the standards. The EPA has taken into account the ability of the various test methods to accurately measure emissions at the levels being demonstrated by the best performing EGUs in establishing the final limits. This has been done through use of the 3XRDL (discussed elsewhere in this preamble and the Response to Comments document) and through adjustments to the sampling time requirements for certain of the HAP.

7. Comments on Technical Approaches

Comment: Commenters disagreed with the EPA's use of data from multiple units exhausting through a common stack and argued that the EPA unreasonably treated data from multiple units exhausting through a single stack as multiple data points in establishing the MACT floors. The commenters believe it is improper to count a single data point from a multiple-unit common stack as multiple data points. The commenters state that where two units exhaust through a common stack, the performance is not that of two sources, but only one. The commenters indicate that emissions performance that is actually achieved reflects combined operation, which cannot rationally be split into two parts (data points) because this emissions performance was not achieved by two separate sources. Commenters assert that although it may be acceptable for the EPA to surmise that the combined performance of multiple EGUs and pollution control devices represents an emissions control strategy that could be a best performer, thereby entitling the Agency to use the data at all, the fact is there is only one performer not two. Commenters contend that

apart from being inconsistent with applicable MACT case law, counting combined stack emissions as two or more data points is unreasonable because it dampens variability and over-represents the emissions data by creating multiple "performers" or sources when there is in fact only one. Commenters note that in the major-source Industrial Boiler NESHAP, the EPA argued its approach of creating two data points from a single combined stack data point is reasonable because it cannot separate the comingled fraction of the emissions from the different emission points. Commenters state that this is irrelevant, believing that there is no basis to separate these emissions because the MACT floor is based on best performing sources and there is only a single source.

According to commenters, the EPA cannot determine what amount of the overall performance of a combined stack data point is the specific result of the combination. Commenters assert that the EPA also argues that applying the emissions equally to multiple units exhausting through a single stack "accurately represents the emissions of those units on average." Commenters believe that is simply not correct and there is no plausible factual basis for that statement, believing that there is no unit that "achieved" those emissions. Rather, the data represent the combined weighted average of two units, without knowing how either unit actually performed. One commenter also stated that in several instances when a facility operated tandem or multiple EGUs but only submitted a single stack measurement, the EPA used the single stack measurement to represent Hg emissions from the facility's other stacks.

Response: The EPA disagrees with commenters. As in the major-source Industrial Boiler NESHAP, the

EPA continues to believe that the emissions from the common stack represent the average emissions of the EGUs exhausting to the common stack and are representative of both EGUs. Commenters have provided no data to support the contention that this assumption is false. In addition, commenters' contention that distinct EGUs (*i.e.*, boilers) are one source if they emit out of a common stack is not consistent with the CAA section 112(a)(8) definition, which clearly applies to the individual boiler units with a capacity of more than 25 MW. It would not be reasonable in light of that definition to consider the emissions from two boilers to a common stack as the emissions of one EGU. The EPA only used data from combined stacks where both EGUs were operating or where the owner/operator certified that no air leakage could occur. The EPA expects that companies will comply with the final rule by conducting testing at the common stack as that is usually where the sampling locations are (rather than in the intermediate ductwork) and will report the results as being for each EGU.

The EPA has reviewed the data based on comments received and does not believe that there are any inconsistencies in the data set used for the final rule. In the MACT floor analysis, the EPA only used data from stacks that were tested or for which test data were provided. These stack measurements were not used to represent emissions from other, non-tested, stacks in the MACT analysis.

8. Alternative Units for Emission Limits

Comment: Several commenters submitted a variety of alternatives to the input- or output-based MACT floor limits as means of establishing the MACT floors. Some commenters suggested emission reductions or

removal efficiencies. These commenters suggest that a percent reduction MACT metric be considered as an alternative, and not a substitute, to some of the proposed MACT numerical limits, particularly those that appear too problematic to meet in reality. A necessary data format and protocol could be developed for some HAP, such as Hg, that would allow an appropriate percent reduction alternative to be developed. Commenters believe that the Brick MACT decision stands for the proposition that a MACT level cannot be based on a specific technology; commenters are advocating that a percent reduction format would specify the level or reduction but would not dictate any specific control or methodology.

Comments were also received that some state programs contain Hg emission limits that are more stringent than the EPA's proposed emission limits. The programs of Connecticut, Massachusetts, New Hampshire, New Jersey, and New York were noted. Commenters provided information on these states' Hg emission limits, which often are in the form of either a lb/TBtu format or a percent reduction. Commenters noted that EGUs in these states were in compliance with the state regulations and, therefore, the EPA's emission limits should be more stringent.

Response: The EPA disagrees with the commenters' suggestion that a percent reduction standard should be included in the final rule. The EPA notes that the inability to account for Hg removed from the coal prior to combustion was not the only reason provided for not using a percent reduction format. As noted in the proposal preamble *(76 FR 25040)*, we did consider using a percent reduction format for Hg. We determined not to propose a percent reduction standard for several reasons. The percent reduction format for Hg

and other HAP emissions would not have addressed the EPA's desire to promote, and give credit for, coal preparation practices that remove Hg and other HAP before firing because we did not have the data to account for those practices. Specifically, to account for the coal preparation practices, sources would be required to track the HAP concentrations in coal from the mine to the stack, and not just before and after the control device(s). Such an approach would be difficult to implement and enforce. Moreover, we do not have the data necessary to establish percent reduction standards for HAP at this time. Depending on what was considered to be the "inlet" and the degree to which precombustion removal of HAP was desired to be included in the calculation, the EPA would need (*e.g.*) the HAP content of the coal as it left the mine face, as it entered the coal preparation facility, as it left the coal preparation facility, as it entered the EGU, as it entered the control devices, and as it left the stack to be able to establish percent reduction standards. We do not have this type of information.

The EPA believes that an emission rate format allows for, and promotes, the use of pre-combustion HAP removal processes because such practices will help sources assure they will comply with the proposed standard. A percent reduction requirement would likely limit the flexibility of the regulated community by requiring the use of a control device. In addition, as discussed in the Portland Cement NESHAP *(75 FR 55002;* September 9, 2010), the EPA believes that a percent reduction format negates the contribution of HAP inputs to EGU performance and, thus, may be inconsistent with the D.C. Circuit's rulings as restated in the *Brick* case *(479 F.3d at 880)* which say, in effect, that it is the emissions achieved in practice (*i.e.*,

emissions to the atmosphere) that matter, not how one achieves those emissions.

The 2010 ICR data confirm that plant inputs likely play a role in emissions to the atmosphere. These data indicate that some EGUs are achieving lower Hg emissions to the atmosphere at a lower Hg percent reduction (*e.g.*, 75 to 85 percent) than are other EGUs with higher percent reductions (*e.g.*, 90 percent or greater). However, we are not sure whether these data accurately reflect the total percent reduction mine-to-stack because we do not have all the data necessary to make that determination. Thus, we proposed to establish numerical emission standards for Hg HAP emissions from EGUs and we are finalizing numerical emission standards. The same issues prevent us from considering percent reduction standards for the other HAP emitted from EGUs.

With regard to the comments relating to some state programs being more stringent than the EPA's proposed limits, the EPA would note that many of the programs identified by one commenter have an "either/or" format for their Hg standards. That is, an EGU can either meet an emission limit (*e.g.*, lb/TBtu) or achieve a percent reduction. The commenter did not note which form of the standard the EGUs were meeting so it is unclear whether the standards are in fact more stringent. In any case, CAA section 112(d) does not mandate that federal standards be more stringent than state requirements for HAP emissions. Furthermore, states are authorized to establish standards more stringent than this final NESHAP so promulgation of this rule will in no way affect a source's responsibility to comply with an otherwise applicable state Hg or other HAP standard.

9. Beyond-the-Floor

Comment: Several commenters stated that the proposed beyond-the-floor Hg limit for low rank coal EGUs is based on too little data and is technically and economically unattainable, noting that the EPA's proposed beyond-the-floor limit is based on only three samples from a single test held at only one EGU, which is not enough data to develop such a limit, especially as more data were available for this EGU in the database. Commenters noted that although this one EGU may have been able to achieve the proposed limit during this one test, the three samples are not adequate to demonstrate the long-term ability of this EGU to meet that limit consistently, let alone the long-term abilities of the top 12 percent of all low rank coal EGUs to meet that limit consistently. Given Texas lignite's particularly high rates of variability of Hg concentration, and the inability to minimize this variability, the commenters believe that the EPA is obliged to have more, not less, data to support the proposed beyond-the-floor Hg limit for low rank coal EGUs. One commenter added that the EPA's decision to require a beyond-the-floor limit for the low rank virgin coal subcategory does not comply with CAA section 112(d)(2). Some commenters also contended that the EPA failed to include the cost of a baghouse in its beyond-the-floor analysis. They note that, according to the EPA, in order to comply with the proposed EGU MACT rule, units will either fuel switch to a lower Hg fuel or retrofit air pollution controls.

Response: The EPA notes that all of the low rank virgin coal-fired EGUs for which data were submitted in response to the 2010 ICR were meeting the Hg floor limit (11 lb/TBtu). Four of the EGUs have ACI systems installed and three of the four EGUs tested were also meeting the beyond-the-floor Hg emission limit of 4.0

lb/TBtu. Those three units were achieving control levels of greater than 95 percent (fuel to stack). The other low rank virgin coal-fired EGUs that are not currently meeting the beyond-the-floor emission limit do not have installed Hg-specific controls. An analysis of the Hg content of the fuel used during the 2010 ICR testing suggests that control in the range of 80 to 90 percent (fuel to stack) would be needed to meet the beyond-the-floor limit of 4.0 lb/TBtu. One low rank virgin coal-fired EGU achieved 75 percent control with no Hg-specific control technology (*e.g.*, ACI).

The EPA believes that its beyond-the-floor analysis is appropriate, including the costs analyzed. The EPA's cost analysis is meant to serve as an average for all sources in the subcategory recognizing that some EGU's costs will be more and some less; EGUs whose costs are higher are not exempted from the regulation. Further, five EGUs in the subcategory are meeting the final beyond-the-floor limit based on available data (*See* the MACT Floor analyses in the docket), and, in any case, CAA section 112(d) does not require that a specified percentage of sources in a category or subcategory be able to meet the MACT standard that is established. This is even truer for beyond-the-floor standards which are set at levels beyond what the average of the best performing sources are achieving in practice and instead based on what is achievable. Commenters have failed to provide any data that supports the contention that some EGUs in the subcategory will not be able to achieve the standards with additional controls.

Comment: Commenters indicated that the EPA has not justified a beyond-the-floor limit for Hg for new IGCC units. The EPA's choice of the beyond-the-floor Hg limit for new IGCCs is not derived from IGCC test

data from the 2010 ICR and commenters allege that the EPA has not provided adequate justification for its decision from a technology capability assessment. Commenters note that ACI for Hg treatment of coal-derived syngas is not in use in any operating IGCC plant today, nor can it be used in the same fashion as it is used at conventional coal-fired EGUs. Commenters assert that the EPA also lacks data with respect to new IGCC units, yet the EPA proposed beyond-the-floor MACT limits for new IGCC sources. The commenters assert that the EPA's limits for new IGCC sources are based on beliefs, predictions, projections and design target assumptions. The limits from the 2007 DOE Report referenced in the preamble are based on environmental target assumptions. These IGCC environmental targets were chosen to match Electric Power Research Institute (EPRI) design basis from their Coal Fleet for Tomorrow Initiative. Commenter states that EPRI notes that these were design targets and were not to be used for permitting values. Commenters assert that the EPA has simply not justified its process for going beyond-the-floor for new IGCC units and that, without sufficient justification, the EPA actions are unsupported.

Two commenters provided permit information, based on IGCC units currently under construction, for PM and Hg emissions. One commenter requested that the proposed new MACT floor limit for PM be modified to address the two scenarios for duct burners at IGCC plants, syngas-fired and natural-gas-fired. The commenter requested the 0.050 lb/MWh limit be increased to at least 0.068 lb/MWh based on gross energy output from the combined cycle generating unit when operated with duct burners fired with syngas. The 0.068 lb/MWh value is consistent with the calculated emission ceiling for its permit to construct for this

operating scenario. According to the commenter, there is not sufficient experience with syngas turbines for manufacturers to guarantee performance in the 0.050 lb/MWh range. The 0.0681b/MWh performance basis proposed by the commenter was calculated based on the emission guarantees that the commenter was able to obtain for a turbine fired on the syngas. The commenter also requested that the 0.050 lb/MWh limit be increased to 0.083 lb/MWh based on gross energy output from the combined cycle unit when operated with duct burners fired by natural gas. The commenter indicated that, depending on market conditions, the syngas produced at an IGCC may have more value as a raw material for producing co-products than it would have as duct burner fuel. Where that is the case, the economic viability of an IGCC would be enhanced by firing the duct burners on natural gas and diverting that syngas to manufacture of a co-product. The commenter's air permits are currently based on the use of syngas as duct burner fuel; however, the commenter is currently examining an alternative operating scenario that may result in amendments to the air permits to authorize firing natural gas in the duct burners. Commenter states that preliminary calculations indicate that the PM limit would need to be set at 0.083 lb/MWh gross energy output when operated with duct burners fired with natural gas.

The commenter also noted that there is not sufficient test data to precisely predict the Hg emissions performance of even the best-controlled IGCC units, other than that IGCC Hg emissions are expected to be much less than those for EGUs that directly burn coal. In its permit application, the commenter proposed to establish a new standard for Hg removal in IGCC units by treating the syngas in catalytic reactors. The catalytic reactor system is expected to achieve greater

than 95 percent Hg removal using either sulfur-impregnated activated carbon or alumina catalyst. In the absence of actual stack test data, the commenter has had to estimate expected emissions based on engineering estimates of how much Hg may arrive in the syngas routed to the catalytic reactors. Based on these engineering estimates and 95 percent Hg removal in the catalytic reactors, the commenter believes that the resulting Hg emission limit for a state-or-the-art IGCC unit would be 0.003 lb/GWh, which is much less than the Hg emissions for EGUs that directly burn coal.

The commenter notes that IGCC units are still in their infancy. Funding for them will be very difficult or unavailable if there is a regulatory limit below the level that can be supported by vendor guarantees. Given the important role that IGCC units may have in meeting global energy and climate stability goals, the commenter believes it would be a mistake to erect barriers to the implementation of this technology. The commenter stated that the EPA can reevaluate the appropriate levels for future IGCC units after demonstration units which incorporate effective controls have been built and tested.

Response: The EPA is not finalizing the proposed new source standards for IGCC units. As commenters noted, EPA proposed beyond-the-floor limits for IGCC units based on the performance of PC-fired EGUs and solicited data from IGCC units that would represent what a new IGCC could achieve. We received information that there are new IGCC units permitted and under construction. The EPA believes one IGCC unit under construction for which permit data were provided is representative of both current technologies and of IGCC units that will be built in the near-term

future. Therefore, the EPA believes these permit levels should be the basis of the new source IGCC emission limits and the Agency is finalizing the PM and Hg limits on that basis, as that source will be required to comply with its permitted limits once constructed and it is a similar source. However, permit limits were only provided for PM and Hg; therefore, the EPA is finalizing the new source limits for acid gas HAP based on data from the best-performing of the existing IGCC units for the respective HAP.

B. Rationale for Subcategories

Many commenters stated that the EPA should have proposed more subcategories, while others believed that too many subcategories were proposed. Many different issues were raised by commenters, and some of the key issues that were considered in the final rule (some of which led to changes in the final rule) include: the technical deficiencies in the definition for the low-Btu coal subcategory; additional subcategorization of the coal-fired EGU population; the need for subcategorization of distillate vs. residual oil-fired EGUS; the need for a limited-use subcategory for EGUs that operate for only a small percentage of hours during a year; and the need for a non-continental liquid oil subcategory for island units that have limited fuel options and other unique circumstances. The comments and the EPA responses are provided below.

In general, the EPA has reviewed the data provided and continues to believe that the coal-fired EGU subcategories proposed are the only ones supported by the data, though we have revised the basis for EGUs designed to burn low rank virgin coal as discussed above. The EPA may not subcategorize by air pollution control technology type as requested by a few commenters. Further, the EPA has reviewed the other

suggested coal-fired subcategories and finds no basis for further subcategorization (*e.g.*, based on boiler design, boiler size, or duty cycle).

1. Coal Subcategories

Comment: Commenters noted that although other subcategories had been evaluated, including subcategorization of other coal ranks, no other coal rank subcategorization was proposed. Commenters submit there should be subcategories for the coal ranks of bituminous, subbituminous, and lignite. The commenters noted that such treatment would be consistent with past practice (*e.g.*, CAMR where the differences in the type of emissions of Hg due to the different chemical properties of coal within differing fuel ranks was discussed). Commenters note that activated carbon has been shown to be very effective when used in combination with low chlorine coals (such as western subbituminous coals); however, activated carbons can suffer from poor performance when used with high sulfur coals. Commenters indicate that firing high sulfur coals (especially when an SCR is also used) can result in sulfur trioxide (SO_3) vapor in the flue gas stream. The SO_3 competes with Hg for binding sites on the surface of the activated carbon (or unburned carbon) and limits the effectiveness of the injected activated carbon. But another commenter noted that an SO_3 mitigation technology, such as dry sorbent injection (DSI, *e.g.*, trona or hydrated lime), applied upstream of the ACI can minimize this effect.

Commenters also stated that without further subcategorization the economic impacts on individual Midwestern states will be particularly acute as huge segments of the U.S. coal reserve will be disenfranchised by this rule. According to the commenters, the

EPA did not even attempt to legitimately analyze this issue and, thus, in their opinion the Agency's proffered rationale for declining to further subcategorize based on the acid gas standard is belied by the record. The commenters believe that the EPA needs to better align this rule with its previous position in CAMR and further subcategorize based on coal type.

Other commenters are opposed to any further subcategorization based on coal rank. Because many sources blend several ranks of coal on a regular basis, commenters believe that establishing coal rank subcategories would create numerous opportunities for sources to game the regulations and substantially increase emissions. Commenters stated that there is no need for such an approach since modern pollution controls can accommodate a wide range of coals. These commenters believe that EGUs firing different ranks of coal are not fundamentally different in size, class, or type in a way that impacts emissions or that limits the availability of controls. The commenters believe that emissions of fuel-dependent HAP can be controlled by either changing the fuel prior to combustion or by removing the HAP from the flue gas after combustion. Commenters state that ACI systems, DSI controls, and PM controls are available for installation at units firing sub-bituminous coal and are equally available for units firing bituminous, anthracite, or lignite coal. These commenters also believe that as long as a control option is commercially available, the cost for a particular EGU is irrelevant to the EPA's development of emission standards based on MACT. Commenters stated that subcategories based on coal rank would make a meaningful consideration of fuel switching impossible, contrary to the judicial mandate to consider substitution of materials in setting the floor and the statutory

mandate to consider substitution of materials in the beyond-the-floor analysis.

One commenter stated that although they previously supported the subcategorization of coal-fired units on the basis of coal rank, they no longer object to grouping units that burn bituminous and subbituminous coals in a single category because the prior basis for subcategorization no longer exists. The commenter indicated that at the time of CAMR, it was widely recognized that although coal-fired units combusting bituminous coal, with its higher concentration of chlorine and, therefore, ionic Hg, could effectively limit Hg emissions by utilizing existing control technologies such as scrubbers, units burning subbituminous coal could not do so with the same controls because of the coal's higher levels of elemental Hg. The commenter stated that activated carbon was only a fledgling and unproven technology at the time; today, however, activated carbon has been proven, and units burning bituminous and subbituminous coal can achieve the same levels of emissions for Hg and other HAP. Consequently, the commenter believes the prior basis for subcategorization no longer exists and the commenter, therefore, agrees that coal-fired EGUs burning bituminous and subbituminous coals ought to be grouped in a single category.

Response: The EPA disagrees with commenters that additional coal-fired subcategories are warranted and has not provided any in the final rule. Commenters are correct that additional subcategorization was proposed in January 2004. Whether or not such subcategorization was warranted at that time, the EPA believes that the current conditions are such that, even if appropriate at that time, such further subcategorization is not appropriate at this time.

When all of the factors noted by commenters have been reviewed, with the exception of Hg for certain units, as discussed above, the EPA does not believe that the HAP emissions to the atmosphere are sufficiently different from coal-fired EGUs to warrant further subcategorization. There are EGUs firing bituminous, subbituminous, and coal refuse among the top performing units for Hg and EGUs firing bituminous, subbituminous, lignite, and coal refuse are all among the top performers for the acid gas HAP and non-mercury metallic HAP indicating that the MACT floor limits established based on these units are achievable by units burning all ranks of coal.

As noted by commenters, ACI, not fully developed in 2004, is now able to effect Hg control levels on subbituminous coals such that similar emissions to the atmosphere may be achieved as those achieved by higher-chlorine bituminous coals when FGD systems are used or by coal refuse EGU with less controls. Thus, in looking at the total system, similar emissions to the atmosphere are achieved by all of these coal ranks. The EPA has addressed elsewhere in this document its rationale for not subcategorizing by coal chlorine content. The EPA does not believe that any fundamental discrimination between coal ranks will occur as a result of the final rule, though clearly some sources will be required to install greater controls to comply with the final standard. We maintain that such result is consistent with the intent of CAA section 112 standards, which are not intended to have an outcome whereby all sources can comply with final standards without any action.

The EPA agrees, in theory, that EGUs are designed around a basic set of coal characteristics. However, the 1999 ICR demonstrated that numerous EGUs have

conducted trial burns and gained sufficient experience such that co-firing blends of various coal ranks is now common practice. In fact, the EPA believes that such blends may be modified daily, depending on the characteristics of the coal being burned and on the level of generation needed. The extent of blending, and the ability to switch the blends on short notice, does not lend itself (or, in fact, argue for) additional subcategorization.

The EPA disagrees with any assertion that the EPA ignored possible subcategorization approaches or that it has insufficient data upon which to base or evaluate various subcategories. The EPA fully examined the record, which demonstrates that coal-fired EGUs, with the exception of certain units for Hg, have similar HAP emissions profiles and that similar control approaches are available to such EGUs. Although commenters suggested additional subcategories were warranted, they failed to provide sufficient data to support their proposed alternative subcategories. As noted elsewhere, the EPA does not disagree with commenters that there are some differences in EGUs. However, the EPA does disagree with commenters that those differences result in differences in emissions to the atmosphere such that additional subcategorization is justified.

Failing to demonstrate that coal-fired EGUs are different based on emissions, the commenters turn to economic arguments, asserting that failing to subcategorize will impose an economic hardship on certain sources. Congress precluded consideration of costs in setting MACT floors, and it is not appropriate to premise subcategorization on costs either. See S. Rep No. 101-228 at 166-67 (5 Legislative History at 8506-07) (rejecting the implication that separate

categories could be based on "assertions of extraordinary economic effects"); *see also NRDC v. EPA 489 F.3d 1364 (D.C. Cir. 2007)* (holding that EPA properly declined to create a subcategory for a particular source and rejecting the argument that the source may have to incur more costs to comply with the rule without such subcategory).

The final limits are based on EGUs currently operating with available controls. As noted above, the record shows that the various types of EGUs are represented in the floors, with the exception of certain units for Hg, which indicates that the levels are achievable by such units. Thus, the data actually show that the MACT standards are achievable for a wide variety of EGUs.

In addition, the EPA believes it has fulfilled the CAA section 112(c)(1) directive that "[t]o the extent practicable, the categories and subcategories listed under this subsection shall be consistent * * *" with those of CAA section 111, notwithstanding commenters assertion to the contrary. The decision on whether to directly align CAA sections 112 and 111 subcategories is discretionary and EPA has reasonably exercised its discretion in declining to create additional subcategories for coal-fired EGUs based on the record, with the exception of certain sources for Hg.

Finally, the EPA disagrees with the commenters that suggest that EPA lacks the legal authority to consider material inputs when considering subcategories. We agree, however, that material inputs must be considered when establishing MACT standards for the subcategories that are established. We also believe a meaningful consideration of fuel switching can occur even if sources are subcategorized based on fuel inputs

because EPA considers fuels switching in evaluating potential beyond-the-floor alternatives.

Comment: One commenter stated that the EPA should establish an existing source acid-gas subcategory for high sulfur or high chlorine coals because the same factors that the EPA relied on to support a low rank virgin coal subcategory for Hg are also present in the high sulfur or high chlorine coal context. The commenter stated that the data indicate that even well-controlled units burning high sulfur coals would not be in the top performers for acid gases even at removal rates of 95 or 96 percent. The commenter added that absent such a subcategory, about 12 percent of coal deliveries (2005 data), and the vast majority of coal shipped from the states of Indiana, Ohio, and Illinois (2008 data), would become unusable. The commenter expressed support for the alternative SO_2 standard for units unable to meet the HCl standard; however, the commenter also believed that it is appropriate to establish a coal chlorine or sulfur content-based subcategory for the alternative SO_2 standard. The commenter stated that coal testing data indicate a clear break in chlorine concentrations in the coals burned by EGUs, as well as in sulfur content. The commenter indicated that there are factors supporting a high sulfur or high chlorine coal subcategory that are similar to those that the EPA relied upon to support a Hg subcategory for low rank virgin coal. According to the commenter, the EPA's key rationale for a Hg subcategory for low rank virgin coal was that no low rank virgin coal-fired unit appeared in the "top performing 12 percent of sources, indicating a difference in the emissions for this HAP from these types of units." The EPA did not establish other subcategories because "the data did not show any difference in the level of HAP emissions and,

therefore, we have determined that it is not reasonable to establish separate emissions limits for other HAP." The commenter indicated that the EPA does not need emissions data to know that even well-controlled units burning higher sulfur coals would be unable to meet the alternative SO_2 emissions rate, and would therefore also not appear in the top 12 percent of performing units.

Response: The EPA disagrees with commenters that subcategories should be established for high sulfur and high chlorine coals. It appears from the comments that it is not in fact the chlorine content that is at issue but the sulfur content of the coal. Commenters state that they are unable to meet the HCl limit, but they only provide information indicating it would be difficult to meet the alternative equivalent SO_2 limit. In fact, our data show that coals with chloride contents as high as 2,100 ppm (0.16 lb/MMBtu) were burned by EGUs making up the MACT floor pool of sources for the final HCl emission limit and that the best-performing unit was burning coal with a maximum chloride content of 1,200 ppm. The median chloride level for bituminous coals identified from data submitted through the 1999 ICR was 1,030 ppm so we believe that the coals represented in the MACT floor pool indicate that the final limits are achievable with high-chlorine coals. We have determined that HCl removal is very effective using a number of different types of FGD systems. Absent information demonstrating that sources are unable to meet the proposed HCl limit due to the chlorine content of the coal, we believe it is unnecessary and inappropriate to consider subcategorizing based on chlorine content in the coal.

In addition, as noted above, the SO_2 limit is an alternative equivalent standard that is available to

sources that have an SO_2 control and CEMS and operate the controls at all times. The EPA did not provide the alternative equivalent standard for sources that could not meet the HCl limit as one commenter suggests; instead, we provided the standard as a convenience and cost saving measure to EGUs with installed FGD systems because we recognize that many EGUs have SO_2 CEMS. Sources are required to comply with the HCl limit as a surrogate for all the acid gas HAP or the SO_2 limit as an alternate equivalent standard. Commenters have not demonstrated that they are unable to meet the HCl standard and our data show that the standard is achievable even for high chlorine coals.

Comment: Several commenters supported the development of a separate subcategory for fluidized bed combustors (FBC) or circulating fluidized bed (CFB) EGUs. The commenters encouraged the Agency to consider subcategorization of FBC EGUs for Hg emissions noting that the industry has long contended that the design, construction, and operation of FBCs are different than conventional boilers and that FBCs employ fundamentally different processes than conventional PC-fired EGUs. The selection of an FBC unit over a conventional PC boiler is driven in large part by fuel characteristics. The commenters assert that, as a result, the emissions profile of FBC units generally differ from conventional PC boilers because FBC units more advantageously combust waste coals, as well as coal blends with other carbonaceous material. The commenters stated that the EPA did not discuss the design differences between FBC units and PC units in the preamble to this proposed rule unlike what the Agency did when it previously proposed Hg MACT limits in January 2004. Commenters state

that, for these reasons, FBC units can be considered a distinct type of boiler.

The commenters noted that an examination of the 40 "best performing" units for Hg emissions in the proposed MACT floor spreadsheet showed that 14 of those units are FBC units. The commenters maintained that had FBC units performed as well as conventional PC boilers, 2 units would have been expected to be in the top 40. The commenters allege that the far higher percentage of FBCs in the top 40 leads to the conclusion that these units are different from conventional PCs with regard to Hg emissions and, as a result, should have been placed in their own subcategory. Further, commenters noted that the largest FBC has a nameplate capacity of about 300 MW while the largest conventional boilers have nameplate capacities of around 1,300 MW.

The commenters stated that FBCs combust relatively large coal particles in a bed of sorbent or inert material at a lower degree of combustion efficiency. Fluidized bed units operate at less than half of the temperature of a conventional boiler and have much longer fuel residence times. Conventional boilers pulverize coal to a very fine particle size to maximize combustion efficiency and minimize unburned carbon. As a result, the commenters noted that FBCs typically have higher levels of unburned carbon present in the ash, which behaves much like activated carbon and helps promote more efficient Hg removal. Accordingly, commenters maintain that Hg emissions of FBC boilers and PC boilers are statistically different, with emissions from FBCs significantly lower than those from PC boilers. According to commenters, this statistically significant difference in the Hg emissions profiles for these two distinct boiler

technologies argues in favor of the creation of a separate subcategory for FBCs, as there is no control technology that PCs could install that would result in emissions reductions similar to those achieved by FBCs. The active quantity of calcium oxide (lime-CaO) available in a FBC boiler is also orders-of-magnitude greater than compared to a PC boiler, whose alkalinity is derived solely from the coal's mineral content. Significantly higher CaO can alter the process chemistry in the boiler, including the oxidation levels of Hg.

One commenter stated that the EPA properly declined to subcategorize units based on design type where there is no indication that any physical distinctions among unit designs have a meaningful and substantial impact on HAP emissions. The commenter indicated that it would be inappropriate to subcategorize FBCs because there is no evidence to support a determination that FBC design is responsible for a unit falling in or out of the top 12 percent for a particular HAP.

Response: The EPA acknowledges that there are design and operation differences between conventional PC-fired EGUs and FBC/CFB EGUS; however, the commenters are incorrect in asserting that the HAP emissions levels and characteristics are sufficiently distinct from other coal-fired EGUs to support subcategorization. Further, commenters fail to note that FBC EGUs were not subcategorized in CAMR even though, as commenters note, such design and operation differences were cited there. The fact that FBC units operate at lower temperatures is of no consequence as they still operate at temperatures high enough to vaporize Hg.

Commenters assert that FBC units are disproportionately represented among the best performers, with the inference being that they were selected to test in the 2010 ICR because of their boiler design. However, FBC EGUs were not specifically selected as best performers for Hg, as EPA did not select any EGUs based on a determination that they were best performers for Hg (as noted elsewhere, we had no basis for selecting EGUs as being best performers for Hg), and to the extent CFB units were selected in the 2010 ICR, they were selected because we determined they were best performers for non-mercury metallic HAP, acid gas HAP, or organic HAP or because they were randomly selected among the non-best performers for those three HAP groupings. Thus, the CFBs were selected for testing under the 2010 ICR based not on their boiler design but, rather, based on the age and on their PM and FGD control systems (as noted in the Supporting Statement for the 2010 ICR). As many FBC EGUs, including CFB EGUs, are relatively new, they were included in the non-mercury metallic HAP group selected for testing (because their PM controls were among the 175 newest), the acid gas HAP group selected for testing (because FBC was considered to be an FGD system and the units were among the 175 newest), and organic HAP testing (because they were among the newest and, thus, determined to be among the most efficient).

The effect on Hg emissions is not what commenters suggest because, although, as noted by commenters, FBC units may be found among the better performers (among the top 10 EGUs) on the Hg MACT floor spreadsheet, they are also found in the range of 221 to 226 EGUs (of 393 data points). The fact that FBC units have "vastly dissimilar ash properties" that may contain higher levels of lime or unburned carbon in the

fly ash than conventional PC EGUs does not indicate that the overall system behaves any differently with regard to emissions to the atmosphere (the key metric) than a conventional PC EGU with add-on controls. The asserted higher levels of unburned carbon result in a range of effectiveness of Hg control that is similar to that of ACI found on PC EGUs; such ACI control may be found on EGUs that are among the better performers as well as on EGUs as low as 369 on the list of data points. Thus, the EPA disagrees that FBC units are disproportionately represented in the Hg floor and that their inclusion is somehow inappropriate or leads to skewing of the analysis.

All types of coal-fired EGUs other than those we subcategorized are represented in the MACT floors for Hg and all types of EGUs are represented in the floors for the non-mercury HAP. Fluidized bed combustion EGUs are not an exception and such EGUs are found across the range of top performing EGUs for all of the HAP categories: Acid gas, non-mercury metallic, and Hg. In addition, any assertion that non-FBC EGUs are unable to meet the final standards because FBC EGUs are included in the same subcategory (or vice versa) is plainly refuted by the fact that EGUs of all types are currently meeting one or more of the final standards. Thus, the EPA finds no basis for subcategorizing FBC EGUs.

Further, as noted below, the EPA does not believe there is a basis for subcategorizing small EGUs, either FBC or PC. In addition, the data have been re-evaluated based on comments received and an FBC unit is not the basis for the new source Hg MACT floor.

Comment: Many commenters stated that the EPA should have considered additional subcategorization schemes, including one based on EGU size. Commenters

noted that one of the factors that the Administrator can consider under CAA section 112(d)(1) in making subcategorization decisions is unit size. Commenters stated that an analysis of the 2010 ICR data showed a statistical difference between EGUs with a capacity of 100 MW or less and EGUs above 100 MW; other commenters suggested that the cut-off range should be 125 MW. Although large in number (about 27 percent) of all EGUs, these small EGUs only comprise about 5 percent of the coal-fired capacity in the U.S. Thus, commenters assert that if different MACT limits are set for this subcategory of EGUs, it will not have a significant impact on the health effects of HAP emissions. Commenters noted that although emission rates from such small EGUs are greater than those found in the large unit fleet, their contribution to the total EGU emissions is not significant. The costs associated with coming into compliance with the proposed rule by installing new controls would be proportionally much higher for these small EGUs than larger EGUs according to the commenters. The commenters allege that this would force the retirement of generation capacity and threaten electrical reliability without appreciable benefit to the environment.

One commenter stated that in general, the nature of many public power facilities differs from the general population of coal-fired power plants. Public power units tend to be smaller in size, and are often space-constrained by growth in the community surrounding the generating unit since its initial construction. These limitations restrict the ability of these EGUs to achieve the same performance levels of larger, unconstrained EGUs; and, for those EGUs that can comply with the proposed standards, the installation of controls sharply increases the cost of compliance. The commenter stated that the EPA did not

adequately subcategorize to accommodate many small- and medium-sized public power utilities. In particular, the EPA did not avail itself of the opportunity to use a public power electric utility subcategory, rural subcategory, or fuel type subcategories. Other commenters endorsed the establishment of a less than 100 MW subcategory that would reduce the costs of the proposed rule significantly, but only affect 5 percent of the total electric utility sector, and help minimize retirement of uneconomical plants.

One commenter stated that the EPA properly recognized that subcategories based on unit size would be inappropriate because the proposed emission limits are in terms of lb/MMBtu or lb/TBtu and noting that an EGU's total nameplate capacity is wholly unrelated to its ability to achieve the proposed limits. Another commenter opposed any proposal to subcategorize units below 100 MW. The proposed rule does not apply to units less than or equal to 25 MW, and this commenter believed that this is a sufficient threshold for applicability.

One commenter stated that the EPA could establish subcategories for the purpose of temporarily exempting, for example, a subcategory of utilities that meet the definition of small entity for purposes of the proposed rule. The temporary exemption would sunset on a date certain (e.g., 3 years from the effective date of the rule) at which point the sources in the subcategory would become subject to the rule, and a compliance timetable would start to run. The commenter believed that this time-staged promulgation and compliance proposal would greatly increase the chance that the control measures could be added in an orderly and efficient manner with minimal disruption to power markets and grid reliability.

Response: The EPA agrees with commenters who stated that an EGU's size is totally unrelated to its ability to comply with the final concentration-based limits. The EPA examined the size of units within the respective MACT floor pools of sources and found units ranging in size from 25 to 1,320 MW in the HCl floor pool, from 25 to 869 MW in the non-mercury metallic floor pool, and from 47 to 544 MW in the Hg floor pool. Thus, we find no more difference between a 25 MW EGU and (e.g.) a 500 MW EGU than we do between a 500 MW EGU and a 1,300 MW EGU and reaffirm our position that the MW capacity of the EGU is not a determining factor in its emissions. Further, the EPA believes that units of all sizes are owned by both large and small entities.

The EPA examined the effect if EGUs less than 125 MW were subcategorized for Hg. The resultant MACT floor for these EGUs would be 1.0 lb/TBtu on a 30-boiler operating day rolling average, a level more stringent than that developed for the >8,300 Btu subcategory as a whole. We do not believe that this is what commenters envisioned when suggesting such a subcategory but we believe it confirms our analysis of the data that indicates, as noted, these units are controlled in the same manner as other, larger EGUs, such that additional subcategorization is not necessary or reasonable. Further, based on the number of EGUs less than 125 MW in the HCl and PM MACT floor pools, we believe that a similar analysis for HCl and PM would lead to similar or more stringent standards than without the additional subcategory. Thus, units of all sizes are capable of achieving the proposed limits and the EPA is not finalizing a subcategory based on unit size in the final rule.

The CAA authorizes EPA to subcategorize based on "classes, types, and sizes of sources." The EPA does not believe that this provision permits subcategorizing sources based solely on their status as small entities for several reasons. As a threshold matter, commenters provided no information to suggest that EGUs at small entities are different from EGUs owned by other entities. Instead, the commenters' justification for such a subcategory was that the costs to comply with the standards make it more difficult for small entities; thus, the basis is essentially a cost basis and we do not think that is consistent with the statute. Moreover, the legislative history of CAA section 112(d) supports EPA's interpretation that subcategories cannot be based on the cost of compliance. *See* S. Rep No. 101-228 at 166-67 (5 Legislative History at 8506-07) (rejecting the implication that separate categories could be based on "assertions of extraordinary economic effects").

In addition, the EGUs owned by small entities use the same type of fuel as other units, have the same type of combustor designs, and can use the same types of controls, and so there is no difference in the HAP emissions from such units. So, even if we believed a subcategory based on small entities was consistent with the statute, we would decline to include such a subcategory.

Therefore, given the language of CAA section 112(d), the legislative history, and the available information, EPA is not creating a separate subcategory for EGUs owned by small entities.

In addition, the D.C. Circuit has clearly stated that the EPA does not have the statutory authority under CAA section 112 to extend compliance dates past the 3-year maximum compliance time authorized in CAA

section 112(i)(3)(A) except consistent with CAA sections 112(i)(3)(B) and 112(i)(4). *See NRDC v. EPA, 489 F.3d 1364, 1374 (D.C. Cir. 2007)* (finding that "Congress enumerated specific exceptions to the 3-year maximum, which indicates that Congress has spoken on the question and has not provided the EPA with authority under subsection 112(i)(3)(B) to extend the compliance date * * *") (citing also CAA section 112(i)(4)). The EPA may not alter the compliance date based on size or ownership considerations and, thus, we are not providing a separate compliance date for different groups of EGUs in the final rule.

Comment: One commenter stated that the EPA should establish a subcategory consisting of EGUs that had received air construction permits but had not yet commenced construction as of the date of the EPA's proposed rule. The commenter believed that such a category would be justified because a substantial amount of time, money, and effort has been invested in these units. The commenter asserted that imposing new source standards on these EGUs for which the EPA's proposed rule had not been anticipated during their permit consideration would unreasonably and arbitrarily impose additional costs and burdens on these projects and would likely threaten the viability of many of them. The standards for this subcategory would be based on the anticipated performance of these units (as reflected by the permitted case-by-case emission levels), ensuring a reasonable and appropriate level of HAP control without unreasonably and arbitrarily interfering with the development of these units.

Response: Clean Air Act section 112(a)(4) defines a new source as "a stationary source the construction or reconstruction of which is commenced after the

Administrator first proposes regulations under this section establishing an emission standard applicable to such source." The EPA's regulations implementing the CAA section 112 General Provisions define "commenced" to mean "with respect to construction or reconstruction of an affected source, that an owner or operator has undertaken a continuous program of construction or reconstruction or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or reconstruction." *See 40 CFR 63.2.*

The EPA is constrained by the definition of "new source" such that any source that "commenced" construction after the May 3, 2011, proposal date is considered a new source under the statute and the source must comply with the new source standards even if the source received a final and legally effective CAA section 112(g) permit before proposal. It is unclear from the comments whether the sources identified in the comments have commenced construction as defined in the regulations; however, the identified sources are existing sources, not new sources, under the final rule if construction was commenced prior to the proposal date.

Under the final rule, new sources must comply with the standards on the date of promulgation or at startup, whichever is earlier, and existing sources have 3 years to come into compliance with the final standards. Pursuant to the EPA's regulations at *40 CFR 63.44(b)(1)*, however, we may provide in a final CAA section 112(d) standard a specific compliance date for those sources that obtained a final and legally effective CAA section 112(g) case-by-case MACT standard and submitted the information required by

40 CFR 63.43 to the Agency before the close of the comment period. The EPA does not believe it has received such information during the comment period and we are not establishing a separate specific compliance period for sources that obtained final and legally effective CAA section 112(g) standards prior to promulgation of the final rule. In the absence of EPA action on this issue, state Title V permitting authorities are required to "establish a compliance date in the [title V] permit that assures that the owner or operator shall comply with the promulgated standard [] as expeditiously as practicable, but not longer than 8 years after such standard is promulgated * * *" *40 CFR 63.44(b)(2)*. Sources with final and legally effective section 112(g) standards should work with their permitting authorities to determine the appropriate compliance date consistent with the EPA regulations.

Comment: One commenter stated that in accordance with CAA section 112(d)(1), based on the government-to-government relationship of the Navajo Nation and the U.S. government, and consistent with the right of sovereignty and self-determination of the Navajo Nation, it may be appropriate to classify EGUs on tribal lands in a different subcategory from those on non-Indian lands. The commenter stated that in accordance with the distinctive status of Indian lands, based on principles of tribal sovereignty and self-determination, the government-to-government relationship, and the flexibility of federal agencies mandated under E.O. 13175, the EPA should classify sources on tribal lands as a unique subcategory of EGUs for which emission standards for NESHAP should be set pursuant to CAA section 112(d)(3).

Response: Pursuant to CAA section 112(d)(1), the EPA may subcategorize sources based on differences in class, type, or size. In the preamble to the proposed rule, the EPA further explains that any basis for subcategorizing (*e.g.*, class) must be related to an effect on emissions, rather than some difference which does not affect emissions performance. The EPA does not agree that a subcategory based on location on Tribal lands is consistent with the statutory authority to subcategorize, and commenters do not explain why emissions would be different for EGUs located on Tribal lands. Absent that showing, EPA believes it would not be appropriate to subcategorize units even if we believed such a subcategory is consistent with the statute. CAA section 112 imposes specific requirements with respect to the methodology that the EPA must use in establishing emission standards for HAP, including Hg emissions from EGUs. Pursuant to CAA section 112(d)(1), the EPA may subcategorize sources based on differences in class, type, or size. The EPA believes, that any basis for subcategorizing (*e.g.*, class) must be related to an effect on emissions, rather than some difference which does not affect emissions performance.

However, the EPA is sensitive to the commenters' concerns and particularly recognizes the significance of Navajo Generating Station to the Central Arizona Project and the water delivery to tribes. As a result, EPA has been consulting with affected Indian tribes and working closely with other federal agencies, including the Department of the Interior, on these issues and intends to work with tribal and other authorities to ensure a smooth transition and address specific issues as they arise.

2. Oil Subcategories

Comment: Several commenters stated that distillate oil, and in particular ultra-low sulfur diesel (ULSD) oil, has fuel characteristics closer to that of pipeline gas than to residual oils. The metals, as well as the ash and nitrogen content, of distillate oils are very low, and the sulfur content of ULSD is approximately the same as that of pipeline natural gas. The commenters state that distillate oil is a more refined product than residual oil and, thus, burns cleaner. According to commenters, separating liquid oil-fired EGUs into two subcategories (distillate and residual oil) would be consistent with the discussion of subcategory differentiation in the rule's preamble which indicates that the division of a category into subcategories is justified if the two subcategories have very different emissions, which is true for distillate vs. residual oils. Distillate and residual oils are also differentiated by their operating requirements. Some commenters stated that as a consequence of the mechanical differences between boilers designed for residual oil vs. distillate oils, and between the fuel-handling requirements for the different fuels, it is not possible to interchange oil types without significant modifications to the oil storage tanks, transfer pumps, piping and valves, flow control systems, burners, and burner control systems. Commenters also noted that some of the EGUs in the EPA's liquid oil-fired database were mischaracterized with regard to the type of oil burned during the 2010 ICR testing.

Some commenters alleged that by combining distillate and residual oil into a single MACT category, the resultant MACT standards cannot be satisfied by a boiler firing residual oil without substantial add-on controls. The commenters asserted that creation of separate subcategories for liquid oil-fired units that distinguish between residual and distilled oil would

render the standards more achievable for distinct subcategories of EGUs and reduce the number of potential plant closures while still advancing the goal of reducing overall emissions. These commenters contend that MACT floors should not be used to eliminate whole classes of existing EGUs through mathematical floor calculations based on data from uncontrolled units and combining boiler subcategories that are not capable of accommodating a different fuel.

One commenter stated that the EPA should not subcategorize liquid oil-fired EGUs based upon different grades of liquid oil. Although different grades of liquid oil may vary in their heat contents or viscosities, the commenter maintained that there is no indication in the rulemaking record that any physical distinction among units burning different grades of liquid oil affects the nature or characteristics of emissions in a way that impacts the availability of controls. According to the commenter, both distillate and residual oil-fired units can apply similar control technologies to reduce HAP emissions, and EGUs firing these fuels do not have physical distinctions that prevent controls from operating effectively. The commenter believes that fuel switching is an appropriate control technology and is available for liquid oil-fired sources. Residual fuel oil contains higher levels of contaminants, including HAP, than distillate oil, and because a regulated entity can readily burn cleaner distillate oil in lieu of residual oil, it is inappropriate to subcategorize based on the distillation fraction of the liquid oil. Thus, according to the commenter, the grade of liquid-oil fuel does not provide a reasonable basis for subcategorizing various groups of liquid oil-fired EGUs. Another commenter alleges that the EPA did not list distillate oil-fired EGUs in the 2000 Finding.

Response: The EPA has reviewed the data and determined that it is not necessary to subcategorize distillate vs. residual oil. Commenters had noted that the EPA's MACT Floor Analysis spreadsheet at proposal had erroneously assigned the oil type used during testing for some boilers. The EPA reviewed the data and determined that the submitting companies had entered the data incorrectly, or had indicated that two types of oil were fired in different parts of the 2010 ICR responses. The EPA contacted all of the companies with oil-fired EGUs in the 2010 ICR to confirm the oil used during testing. Upon review of these data, it became apparent that units using residual oil with ESPs or distillate oil without control were the best-performing oil-fired EGUs for PM and the HAP metals. Further, although emissions of HAP from distillate oil-fired EGUs are generally lower than those from residual oil-fired EGUs, EGUs burning distillate oil appeared to have higher emissions of some HAP but lower emissions of others.

In addition, the EPA does not agree that distillate oil-fired EGUs were not listed in the 2000 Finding. We believe it is inappropriate to exclude distillate oil-fired EGUs from regulation under the final rule because the Agency did not make a distinction when listing the oil-fired units.

The EPA also disagrees with commenters that by providing the distillate vs. residual oil subcategories as requested, the resultant standards would be more achievable. Were the EPA to subcategorize distillate oil from residual oil, the users of distillate oil would have no means of compliance other than obtaining "compliance" oil from their distributor (which was not indicated as an option by any commenter) or converting

to natural gas and being removed from the subcategory. With no further subcategorization, oil-fired EGUs have the option of installing an ESP or converting to distillate oil for compliance. Commenters did not contend that it was impossible to convert to distillate oil, only that it would require plant modifications. Installing controls would also require plant modifications so sources will be able to evaluate the options and determine the most cost-effective option to comply with the final rule. CAA section 112 is intended to be a technology-forcing statute, and, because both distillate oil- and residual oil-fired EGUs were among the best performing sources in the floor and both types are meeting the final standards, we cannot reasonably conclude that the HAP emissions characteristics of these similar types of units are distinct. Therefore, the EPA is not establishing separate subcategories for distillate and residual oil-fired units in the final rule.

3. Limited-Use Subcategory

Comment: Several commenters stated that EPA should establish a limited-use subcategory for liquid oil-fired EGUs that are required to burn oil during periods of natural gas curtailment. One commenter stated that under New York State Reliability Council Rules, their facility is required by the New York Independent System Operator (NYISO), for reliability purposes, to maintain the capability to burn oil and actually burn oil, from time to time, at varying load levels to help avoid or avert potential natural gas shortages in New York City. The requirements to burn oil under this program are mandatory and are not within the commenter's discretion. The reliability rules require that the commenter's EGUs maintain their co-firing capability to respond to unplanned, emergency scenarios by operating on oil during

required minimum oil burn periods, typically 25 percent oil/75 percent natural gas. The commenter noted that operation using oil at other times or on 100 percent oil during reliability operation periods occurs very infrequently; with natural gas expected to become more available in future years, such an operating scenario will become less likely. However, while the reliability rules remain in place and commenter's boilers are required to operate under his regimen, the commenter believed that it is essential that it be able to do so.

Other commenters noted that requiring installation of emission controls on oil-fired units that operate at a 10 percent oil-fired capacity factor or less is nonsensical and will result in little environmental benefit. Commenters contend that low-capacity factor units emit significantly less HAP than even well-controlled oil-fired units with much higher capacity factors. In addition, commenters allege that stack-testing at such units would be equally impractical and, in addition, would likely require the unit to operate on oil (and emit HAP just for the test) when it would otherwise be off-line or operating on natural gas.

Response: As stated above, after considering comments received, we are establishing a limited-use subcategory for liquid oil-fired EGUs with an annual fired capacity factor of less than 8 percent averaged over each 24-month block period after the compliance date.

At proposal, we solicited comment on establishing a limited-use subcategory for liquid oil-fired EGUs:

EPA is also considering a limited-use subcategory to account for liquid oil-fired units that only operate a

limited amount of time per year on oil and are inoperative the remainder of the year. Such units could have specific emission limitations, reduced monitoring requirements (limited operation may preclude the ability to conduct stack testing), or be held to the same emission limitations (which could be met through fuel sampling) as other liquid oil-fired units. EPA solicits comment on all of these proposed subcategorization approaches.

As stated above, the EPA did not have sufficient information on limited-use liquid oil-fired EGUs upon which to base a subcategory at proposal. Some sources required to test under the ICR did not submit the data until after proposal. Commenters indicated that their units are different because many of them are only called to service to address reliability issues associated with, for example, natural gas curtailments. The commenters further indicated that their units are different because of the generally infrequent use and the sporadic, and at times frequent, start-up and shutdown periods (*e.g.*, they are often only required to run for a couple of hours). These factors would lead to differences in the emissions characteristics for these units such that a numeric standard based on base load units would not likely be achievable during the very limited times that these limited use oil-fired units operate.

Based on comments received and our own analysis, we are finalizing a subcategory for limited-use liquid oil- fired EGUs as indicated elsewhere in this preamble. We find that these units constitute a different class and type of units because they are generally only used to address reliability issues associated with, for example, natural gas curtailments, and because they

in fact only run for very limited periods in a year on a seasonal basis.

Although some commenters indicated a prevalence of natural gas/oil co-fired EGUs, the EPA also understands that there are other liquid oil-fired EGUs that do not co-fire natural gas but that could be subject to mandatory operation during periods of natural gas curtailment in their operating area if sufficient non-natural gas capacity is not available. Based on a review of units that report oil use to EPA, in 2010 there were 228 liquid oil-fired EGUs with a capacity factor of less than 5 percent and an additional 10 units with a capacity factor of between 5 percent and 10 percent. Only 2 of these units have capacity factors between 5 percent and 8 percent. This subcategory applies only to oil-fired EGUs that operate on oil alone and act as peaking units, as they generally address reliability issues. We are establishing the capacity factor threshold of 8 percent averaged over each 24-month block period after the compliance date.[320] In addition, as discussed below, we are establishing work practice standard for this subcategory in lieu of numeric emission standards.

Commenters that requested a subcategory for these units noted the dichotomy of establishing a NESHAP to reduce emissions of HAP to the environment while at the same time requiring an EGU to run for the sole purpose of conducting emissions testing and thereby emitting those same HAP. Because the operation of these units is infrequent and unpredictable, performing testing to demonstrate that emission limits are being met requires the sources to be

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[320] Units that co-fire oil and natural gas where the oil combustion comprises 10 percent or less of the capacity factor are natural gas-fired EGUs that are not subject to this final rule.

scheduled to be operated merely for the purpose of performing testing. We realize that similar situations occurred in the gathering of emissions data through the 2010 ICR. However, unlike the case of one-time testing on a limited number of these units, such testing would be mandatory on a yearly basis for all of the EGUs upon the effective date of the final rule. Because requiring testing under this rule would in many cases require operators of these EGUs to schedule operation of these EGUs at times they would not otherwise run, it would result in both extra cost related to the testing as well as extra emissions; therefore, the Agency believes that it is technically and economically impracticable to monitor emissions for these EGUs, and that they should be subject to work practice standards that would not require emissions monitoring.

The annual average capacity factor would be calculated on a 24-month block period, commencing with the compliance date of the final rule. For example, assuming a March 1, 2015, compliance date, the first 24-month block would commence on March 1, 2015, and end on February 28, 2017, with the next 24-month block averaging period commencing on March 1, 2017. We believe the 24-month averaging period is reasonable to account for the fact that units needed to address reliability issues (e.g., natural gas curtailment periods) will be called to service sporadically. A 24-month averaging period provides flexibility to ensure that these units can run if there are large periods when natural gas is unavailable. As explained above, the data shows that most of these units operate for less than 8 percent of the time, and in fact it is usually less than 5 percent. Therefore, when considering whether these units would be able to perform stack testing, in many cases this will be for units that in fact operate

significantly less than 8 percent of the time. In these cases, the EPA does not want to require the units to operate more just for the purpose of running a stack test resulting in additional pollution and cost. With projections for rising oil prices relative to natural gas prices, we expect this trend to continue. Liquid oil-fired EGUs subject to this subcategory would be required to conduct the same initial and periodic tune-up as all other affected units, but would have no other emission limit or work practice requirements.

Although the EPA believes that the ability to burn oil up to 8 percent of the time should address concerns about units that may need to operate using oil during gas curtailments. The EPA recognizes that if there were a period where gas use was more severely limited, such units might need the flexibility to operate for more than 8 percent in one year and less in the next, which is why we are providing the 2-year period; however based on the data we do not think EGUs in this subcategory will exceed even the 5 percent capacity factor that the data indicate is the average level for these sources.

4. Non-Continental Units

Comment: Commenters from affected island EGUs requested that non-continental EGUs be subcategorized from continental EGUs based on their lack of access to natural gas. The commenters urged the EPA to include a "non-continental liquid oil" subcategory in the final rule. According to the commenters, establishing a subcategory for non-continental units is consistent with the approach the EPA has taken in past rulemakings, including the final Industrial Boiler NESHAP. Non-continental EGUs have little or no access to natural gas, minimal control over the quality of available fuel, and disproportionately high

operational and maintenance costs. All oil-fired EGUs operating in Hawaii, Guam, and Puerto Rico combust residual fuel oil exclusively and all are limited by the crude slates of their fuel suppliers. Island utilities can contract with suppliers for certain fuel specifications, such as sulfur content, pour point, flash point, API gravity and viscosity, which the refiners are able to meet primarily by blending and some sulfur removal during the refining process. However, the commenters state that the suppliers do not and cannot economically control for metal content. The crude slate feeding the refinery determines the HAP metal content of the residual oil produced according to the commenters. Because island utilities are dependent on local sources of fuel, they are equally limited by these factors.

Two commenters believe that the separate non-continental subcategory should be expanded to include continental areas that are not interconnected with other utilities and have limited compliance options due to remote locations (*e.g.*, Alaska).

Response: The EPA agrees that the unique considerations faced by non-continental EGUs warrant a separate subcategory for these units and the data show that the difference in location causes a difference in emissions apparently due to the fuel that is available for such units; thus, the Agency has included such a subcategory in the final rule. At proposal, the EPA did not have all of the data from liquid oil-fired units in non-continental areas (*e.g.*, Guam, Puerto Rico) and solicited comment on whether a subcategory should be established, based on the data to be received, for non-continental oil-fired EGUs. The EPA has now received these late data and, based on those data, is finalizing a non-continental subcategory for liquid oil-fired

EGUs in Guam, Hawaii, Puerto Rico, and the U.S. Virgin Islands. The EPA is not aware of any liquid oil-fired EGUs in any of the other U.S. territories that meet the CAA section 112(a)(8) definition but, if there are such units, they would also be part of the non-continental subcategory.

The EPA agrees that the unique considerations faced by non-continental refineries, including a limited ability to obtain alternative fuels that lead to different emissions characteristics, warrant a separate subcategory for these EGUs. The EPA believes that units in this subcategory will comply through the use of cleaner oils or, for PM, through the installation of an ESP. The EPA finds no merit in the comment that Alaska should be included in this non-continental subcategory because utilities in Alaska are not faced with the same access issues affecting island-based facilities.

C. Surrogacy

1. Filterable PM vs. Total PM

Comment: Numerous commenters strongly objected to the use of total PM as the surrogate standard for non-mercury HAP metals. They argued that filterable PM is a better surrogate, especially given EPA's intent to use a PM CEMS for continuous compliance demonstration. Other commenters argued that we should not use a surrogate and instead should require direct compliance with a non-mercury HAP metals standard.

Response: We have decided to use a filterable PM limit for the PM surrogate emission limit in the final rule.

Although the objective of the emission limits we are establishing is to reduce the risks associated with HAP emissions, the limits are based in part upon the demonstrated capabilities of control technologies which are installed on existing sources. Except for Hg, the best PM controls provide the best controls of metal emissions. Emissions measurements of either filterable particulate, total particulate, individual metals, or total metals provide comparable indications that the best level of control is achieved. We can find no significant difference in the emissions that would be achieved by using any one of these emissions measurements.

We re-assessed the relationships between individual metal emissions, filterable PM emissions, total PM emissions, and total $PM_{2.5}$ emissions based on the test results provided through part III of the 2010 ICR. We compared the measured emissions of metals and PM with the uncontrolled emissions estimates and found that control of PM was indicative of the control of metals emissions. In addition, we compared the correlations associated with non-mercury HAP metal emissions and the three forms of PM and found that no specific particulate form provided a consistently superior indicator of better metals control. Although control of filterable PM provided the best indicator of performance for control of some HAP metals, control of total particulate or total $PM_{2.5}$ was nearly as good as an indicator. For control of other HAP metals, total PM measurement provided the best indicator of control performance because it included the vapor-phase metal HAP, although, measurement of the control of filterable particulate was nearly as good an indicator. In addition, certain data analyzed by our Office of Research and Development indicate that a vapor-phase metal, such as Se, can be present as an

acid gas and reduced significantly using acid gas technologies (wet and dry scrubbing). Given that the rule also provides for acid gas control monitoring, and the general equivalency of the different indicators, we have concluded that use of a filterable PM limit as the PM surrogate emission limit is appropriate.

2. Moisture Content of Oil

Comment: A number of commenters stated that studies suggest that chloride in fuel oil can result from contamination during transportation and processing of crude oils and then be emitted as HCl during combustion. For example, the commenters asserted that the chloride contamination of crude oils can occur as a result of the ballasting of tanker ships with seawater. However, the Oil Pollution Act of 1990 requires all new oil tankers to be double hulled and establishes a phase out schedule (by the middle of the decade) for existing single hulled tankers with un-segregated ballasts. Because of the role of seawater contamination in introducing contaminants into the oil, the commenters suggest that the EPA set a percent water content limit for fuel oil at a level of 1.0 percent, rather than setting HCl and HF emissions limits. This would encourage handling and transport practices to limit salt water contamination. One commenter recommended a standard of 1.0 percent water because several of the lowest HCl and HF emitting units currently require percent water (or water and sediment) specifications between 0.5 percent and 1.0 percent.

Response: The EPA is providing the alternative compliance assurance approaches in the final rule for liquid oil-fired EGUs of demonstrating compliance through either specific HCl or HF measurements or by

demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent.

The EPA is not aware of any FGD systems installed on oil-fired EGUs. Thus, it is only the quality of the oil, and the level of HAP constituents contained therein, that can be relied upon for ensuring compliance.

In the proposal preamble, we stated:

> We believe that chlorine may not be a compound generally expected to be present in oil. The ICR data that we have received suggests that in at least some oil, it is in fact present. EPA requests comment on whether chlorine would be expected to be a contaminant in oil and if not, why it is appearing in the ICR data. To the extent it would not be expected, we are taking comment on the appropriateness of an HCl limit. *See 76 FR 25045.*

Commenters refer to certain studies that provide a plausible reason for the chloride/fluoride contamination of fuel oils. We found this reason persuasive and accordingly are providing alternative compliance approaches in the final rule to demonstrate compliance with the acid gas HAP standards. Specifically, sources can demonstrate compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent.

D. Area Sources

Comment: Numerous comments were received both in support of and in opposition to the establishment of generally available control technology (GACT) standards for area source EGUs.

Several commenters in opposition to area source standards stated that the EPA properly established

emissions limitations based upon the performance of all EGUs, rather than distinguishing between major sources and area sources. The commenters believe that Congress did not intend the EPA to distinguish between "major source" EGUs and "area source" EGUs in determining whether and how to regulate EGUs under CAA section 112. These commenters indicated that differentiating major source and area source EGUs for purposes of setting emissions standards is inappropriate in light of the 2000 Finding regarding the threat posed by the absence of regulation of HAP emissions from EGUs. The 2000 Finding was based upon studies whose conclusions regarding the impacts from EGU emissions did not depend upon any relevant distinction between major source and area source EGUs. The commenters note that segregating "major source" and "area source" EGUs would have the perverse effect of eliminating some of the best performing sources from the MACT pool of sources that constitute the "best performing" 12 percent. Many of the best performing sources have employed control technology that brings their emissions below the major source threshold, despite the fact that they are larger units. As a result, the commenters believe that if the EPA created standards for "major source" EGUs based only upon those units, the MACT standards for "major source" EGUs would be less stringent for each of the pollutants than proposed in this Rule. At the same time, the less polluting sources, the "area source" EGUs, could face limits more stringent than those proposed in the Rule. Commenters also note that after reviewing the substantial record in this rulemaking, they believe that the EPA has correctly determined that major and area source EGUs greater than 25 MW have similar HAP emissions and use the same control technologies and techniques to reduce HAP emissions.

Thus, the commenters asserted that the record demonstrates that there is no technical basis for distinguishing between major and area source EGUs for purposes of establishing HAP emission control standards under CAA section 112(d).

Many commenters in support of an area source designation for EGUs stated that the EPA has promulgated area source limits for many source categories of HAP emissions, including most recently industrial boilers and note that GACT controls have been used successfully in many other EPA MACT rules, including rules for iron & steel foundries, electric arc steelmaking, coatings operations, clay ceramics manufacturing, glass manufacturing, and secondary nonferrous metals manufacturing, in order to reduce costs and regulatory burdens. The commenters state that Congress has given the EPA the ability to subcategorize area sources because of their low HAP emissions and low potential impact on human health and that, contrary to the plain language of CAA section 112 and its legislative history, the EPA made no attempt in the proposed rule to distinguish between major sources and area sources for purposes of listing or setting standards. The commenters indicated that where Congress was concerned about the health impacts of specific pollutants from specific sources, it knew how to specify that MACT limits be promulgated (*e.g.*, CAA section 112(c)(6)). The commenters state that area source rules would lessen the regulatory burden of a CAA section 112 EGU rule on many small entities (arguing that many EGUs owned by small public power entities are area sources) and that as many as 12 percent of the EGU population could qualify as area sources. A number of commenters pointed out that the small entity representatives (SER) on the SBREFA panel suggested that the EPA establish

separate emission standards for EGUs located at area sources of HAP and that the standards be based on GACT as allowed under CAA section 112(d)(5). Specifically, the SERs recommended that the EPA establish management practice standards for area source EGUs.

Response: The EPA is not establishing an area vs. major source distinction in the final rule.

The CAA section 112(a)(8) definition of EGU does not distinguish between major and area sources, and we maintain that EGUs are a single source category that contains both major and area sources. The EPA proposed to regulate five subcategories of EGUs without distinguishing between major and area sources for purposes of establishing the standards for the different subcategories. Our approach is wholly consistent with the statutory definition of EGU and reasonable.

Nevertheless, the Agency did examine whether to set separate standards for area source EGUs, because we do not believe that the statute prohibits the Agency from exercising its discretion to establish GACT standards for area sources pursuant to CAA section 112(d)(5) if we determine such standards are appropriate. The EPA is not required, however, to establish GACT standards for area sources, and we believe it may even be unreasonable to do so under the circumstances we identified in the proposed rule as supported by the record of this final rule.

At proposal, we determined that it was not appropriate to establish separate standards for major and area source EGUs, and even if we had exercised our discretion to set separate standards, we would have likely declined to exercise our discretion to set

GACT standards for area source EGUs given our appropriate and necessary finding and the fact that a potentially large number of area source EGUs are in fact large well controlled units.

Some commenters note that there could be as many as 12 percent of the total population that could be classified as area sources. We are not sure of the commenters' point in regard to this statement. As to commenters' statements that many of the area sources are municipal utilities, our information shows that many rather large EGUs (*e.g.*, hundreds of MW) are also area sources, and the commenters have not provided any justification for establishing GACT standards for large synthetic area sources.

Commenters did not provide an evaluation of the health and environmental impacts of the area sources and simply presume that the risks from such sources are lower, even though many of the same commenters noted that these smaller EGUs are often located in densely populated areas where populations are more likely to have adverse health effects from the HAP emissions. Furthermore, other commenters, including some industry commenters, noted that the vast majority of these potential area sources meet the criteria due to the installation of emission controls installed to meet other requirements. According to these commenters, these synthetic area sources would likely be able to meet the limits of this rulemaking and imposition of this rule would not appear to result in the installation of additional controls in a number of cases. We do not know if this assertion is correct but we determined approximately 69 coal-fired EGUs will be able to meet the existing source MACT standards with their current control configuration (out of 252

EGUs that reported data for Hg, PM, and HCl in the 2010 ICR).

Commenters also note that the Agency has exercised its discretion in other NESHAP rulemakings to establish area source limits. Although true, the fact that the EPA has established area source limits in some source categories is irrelevant to similar decisions for different source categories. Commenters have not shown that the circumstances applicable to those other source categories are similar to the circumstances identified for major and area source EGUs (*e.g.*, similar controls, similar emission characteristics, large number of synthetic minor area sources). Further, those other source categories are not statutorily defined in a manner that includes both area and major sources. EGUs are the only source category defined in CAA section 112 and, in establishing the definition of an "electric utility steam generating unit" under CAA section 112(a)(8), Congress included in the EGU source category both area and major sources. Thus, it is reasonable to regulate the EGU category in the manner Congress defined the category. Commenters have provided no legal support for the contention that the EPA must regulate area and major sources in the same category in separate rulemakings, and the EPA has in fact regulated both major and area sources in the same rulemaking even absent a statutory definition that includes both major and area sources. (*See* National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants; *75 FR 54970;* September 9, 2010.)

The EPA considered the totality of the circumstances when determining whether to set separate

area and major source standards for EGUs and also considered whether it would be reasonable to establish GACT standards for areas sources. We reasonably considered whether emissions characteristics of major and area sources are different when determining whether to establish GACT standards, notwithstanding commenters' assertion that such consideration is not correct. That we also consider emission characteristics in subcategorization decisions is of no consequence for area source decisions. Given that the statutory definition of EGUs contains both major and area sources, it was reasonable to evaluate whether there were sufficient differences between area and major sources when deciding whether to exercise our discretion to set separate area and major source standards.

In addition, we find commenter's point concerning CAA section 112(c)(6) odd because EGUs emit several of the CAA section 112(c)(6) HAP (*e.g.*, lead, Hg). Although EGUs were exempted from that provision, the fact that they emit some of the HAP called out for MACT control supports our decision to not establish GACT standards for any EGUs. CAA section 112(d)(5) leaves it to the Agency's discretion to determine whether GACT standards should be established for area sources, and the statute does not require GACT standards or even indicate that such standards are to be the default regulatory approach for area sources. *See 76 FR 25021.* Instead, the statute provides the Agency with discretion and we have exercised it reasonably in this case.

Commenters indicate that many EGUs owned by small entities are potential area sources. However, commenters fail to note that there are also EGUs owned by small entities that are not potential area

sources, and, thus, would not accrue any "lessened regulatory burden" benefit from a decision by the EPA to establish area source standards.

Some commenters state that the EPA's mere assertion that there would be no difference between GACT and MACT to justify an area source finding does not provide sufficient documentation for the decision. But EPA did not say there would be no difference between MACT and GACT. Instead, it stated that it would be difficult to make a distinction given the similarities between the EGUs and major and area source facilities. Specifically, as noted by other commenters, and observable by a review of the MACT Floor Analysis spreadsheets, potential area sources range in size from units near the CAA section 112(a)(8) defined lower size limit to units of hundreds of megawatts. Further, these larger area source units are, for the most part, controlled with the full suite of emission control technologies available (*e.g.*, fabric filters, scrubbers).

In addition, the data that were available in the docket for the proposed rule show that there is little difference between major and area source EGUs individually, and that generally the driver for whether a utility facility is a major or area source depends on the number of EGUs located at a facility (almost exclusively one or two EGUs located at area sources), not on any inherent difference between the EGUs themselves. *See* "Evaluation of Area Source EGUs" TSD, Docket EPA-HQ-OAR-2009-0234. In fact there are a number of EGUs that are quite large that are area sources and others that are small that are major sources. *Id.* This is the case because the acid gas HAP emissions are what drive EGUs to have HAP emissions exceeding the major source threshold. With

a few exceptions, the EGUs located at area sources have FGD or other acid gas controls that reduce the acid gas HAP to area source levels. *Id.* Thus, the majority of sources that currently qualify as area sources were, in fact, major sources prior to installing controls. The exceptions are those units that would likely be able to achieve the MACT level of control for acid gas with minimal use of DSI at a reasonable cost. *Id.*

In addition, the data show that a number of area sources for which we have data are high emitters of Hg and non-Hg metal HAP. *Id.* Pursuant to our appropriate and necessary finding, these HAP pose a significant threat to human health. Thus, even were we to distinguish between major and area sources, which we do not believe is appropriate given the similarities between such sources, we would still decline to set GACT standards, and as such we maintain that MACT standards are appropriate. Moreover, for acid gas HAP, as discussed above, the data indicate that the level of control would likely be the same even if we did establish GACT standards under CAA section 112(d)(5).

We fully evaluated the nature of EGUs, and we do not see a basis on which to distinguish these sources for purposes of setting standards. Thus, we maintain that we reasonably exercised the discretion afforded the Agency under the statute and declined to set separate standards for area source EGUs.

E. Health-Based Emission Limits

Comment: Many commenters noted that in the proposed rule the EPA considered whether it was appropriate to exercise its discretionary authority to establish health-based emission limits (HBEL) under

CAA section 112(d)(4) for HCl and other acid gases and proposed not to adopt such limits, citing, among other things, information gaps regarding facility-specific emissions of acid gases, co-located sources of acid gases and their cumulative impacts, potential environmental impacts of acid gases, and the significant co-benefits estimated from the adoption of the conventional MACT standard. Comments were received both supporting this position and refuting it. Several commenters suggested legal, regulatory and scientific reasons for why HBEL for HCl might be appropriate for this MACT standard. With respect to legal concerns, some commenters indicated that CAA section 112(d)(4) establishes a mechanism for the EPA to exclude facilities from certain pollution control regulations and circumstances when these facilities can demonstrate that emissions do not pose a health risk. Commenters cited a Senate Report that influenced development of CAA section 112(d)(4), where Congress recognized that, "For some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment." (Footnote: S. Rep. No. 101-128 (1990) at 171.) Commenters also cited regulatory precedent for addressing HCl as a threshold pollutant, including the Hazardous Waste Combustors and the Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills NESHAP Commenters requested that the EPA incorporate the flexibility afforded by CAA section 112(d)(4) and allow sources reasonable means for demonstrating that their respective emissions do not warrant further control. The commenters also cited the 2004 vacated Boiler MACT as precedent for HBEL for HCl. The commenters contended that the EPA failed to explain why the health-based emissions

limitations it established in the 2004 Boiler MACT and the justification provided for those limitations could not be used in this case. The commenters also cited a 2006 court briefing where the EPA vigorously defended the HBEL included in the 2004 Boiler rule when it was challenged in the D.C. Circuit (Final Brief For Respondent U.S. Environmental Protection Agency, D.C. Cir. Case No. 04-1385 (Dec. 4, 2006) at 59-65, 69).

Other commenters stated that on August 6, 2010, the EPA adopted a NESHAP for Portland Cement plants that specifically rejected adoption of risk-based exemptions or HBEL for HCl and manganese (Mn). These commenters argue there are no differences sufficient to warrant a reversal of that decision in the EGU MACT standard. The commenters raised concerns that health risk information cited by the EPA for HCl, HF, and hydrogen cyanide (HCN) does not establish "an ample margin of safety" and, therefore, no health threshold should be established. The commenters believe risk-based exemptions at levels less stringent than the MACT floor are prone to lawsuits that could potentially further delay implementation of the EGU MACT.

Some commenters disagreed with using a hazard quotient (HQ) approach to establish a risk-based standard because the HQ would not account for potential toxicological interactions. The commenter noted that an HQ approach incorrectly assumes the different acid gases affect health through the same health endpoint, rather than assuming that the gases interact in an additive fashion. This commenter suggested that a hazard index approach, as described in the EPA's "Guideline for the Health Risk Assessment of Chemical Mixtures," would be more appropriate.

Some commenters dispute that emissions from other EGUs or source categories should be considered when developing an HBEL and they argued that Congress expected the EPA to consider the effect of co-located facilities during the CAA section 112(f) residual risk program instead of under CAA section 112(d). Commenters added that there is no prior EPA precedent for considering co-located facilities from a different source category during the same CAA section 112 rulemaking.

Several commenters disputed the EPA's consideration of non-HAP collateral emissions reductions in setting MACT standards. They contended that the EPA's sole support for its "collateral benefits" theory is legislative history--the Senate Report that accompanied Senate Bill 1630 in 1989 and noted that the D.C. Circuit rejected this use of this theory since the Senate Report referred to an earlier version of the statute that was ultimately not enacted. Instead commenters suggested that other components of the CAA, such as the National Ambient Air Quality Standards (NAAQS), are more appropriate avenues for mitigating emissions of criteria pollutants.

Several other commenters suggested it is impossible to assess an established health threshold for HCl such that a CAA section 112(d)(4) standard could be set without evaluating the collateral benefits of a MACT standard. And, as described in the recently finalized cement kiln MACT rule, setting technology-based standards for HCl will result in significant reductions in the emissions of other pollutants, including SO_2, Hg, and PM. The commenter added that these reductions will provide enormous health and environmental benefits, which would not be experienced if CAA section 112(d)(4) standards had been finalized. These

commenters contended that HCl and other dangerous acid gases produced by EGUs pose substantial risks to industrial workers, as well as surrounding communities, and must be limited by the strict conventional MACT standards.

Several commenters indicated that the current economic climate requires the EPA to balance economic and environmental interests and indicated that HBEL would help target investments into solving true health threats where limits are no more or less stringent than needed to protect public health. Many commenters provided estimates of compliance cost savings if an HBEL is included in this final rule. Some commenters stressed the importance of an HBEL for small entities affected by the regulations. Several other commenters suggested that the EPA should estimate the costs and environmental effects of the HBEL option compared to a conventional MACT standard in order to make an informed decision on the adoption of HBEL.

Response: After considering the comments received, the EPA has decided not to adopt an emissions standard based on its authority under CAA section 112(d)(4) for all the reasons set forth in the proposed rule.

The EPA notes that the Agency's authority under CAA section 112(d)(4) is discretionary. That provision states that the EPA "may" consider establishing health thresholds when setting emissions standards under CAA section 112(d). By the use of the term "may," Congress clearly intended to allow the EPA to decide not to consider a health threshold even for pollutants which have an established threshold. As explained in the preamble to the proposed rule, it is appropriate for the EPA to consider relevant factors

when deciding whether to exercise its discretion under CAA section 112(d)(4), and, notwithstanding commenters' assertions to the contrary, the considerations we include in our analysis are reasonable. The EPA has considered the public comments received and is not adopting an emissions standard under CAA section 112(d)(4) for the reasons set forth in the proposed rule and explained below. We note that this action is consistent with EPA's recent decisions not to develop standards under CAA section 112(d)(4) for the Industrial, Commercial and Institutional Boilers and Process Heaters and the Portland Cement source categories.

As explained in the preamble to the proposed rule, the EPA continues to believe that the potential cumulative public health and environmental effects of all acid gas HAP emissions, not just HCl emissions, from EGUs and other acid gas sources located near EGUs supports the Agency's decision not to exercise its discretion under CAA section 112(d)(4). Additional data for all acid gas emissions were not provided during the comment period, and the data already in hand regarding these emissions are not sufficient to support the development of emissions standards for EGUs under CAA section 112(d) that take into account the health threshold for acid gas HAP, particularly given that the Act requires the EPA's consideration of health thresholds under CAA section 112(d)(4) to protect public health with an ample margin of safety. We note here that EPA agrees with the commenter who pointed out that a better way to evaluate the potential health impact interactions of all acid gases would be to use the approach in EPA's "Guideline for the Health Risk Assessment of Chemical Mixtures" rather than a simple evaluation of individual HQ values for each acid gas, but we further note that use

of such an approach requires a substantially greater knowledge of acid gas emissions than is currently available. We further note that, even if cost were a relevant factor in setting standards under CAA section 112(d)(4), since the data are not available that would allow us to develop an acid gas HBEL appropriate to protect public health with an ample margin of safety, we cannot determine whether such standards would have any cost savings associated with them or not. In addition, the concerns expressed by the EPA in the proposal regarding the potential environmental impacts and the cumulative impacts of acid gases on public health were not assuaged by the comments received because no significant data regarding these impacts were received.

The EPA also received comments recommending not only that the EPA establish emissions standards for acid gases pursuant to CAA section 112(d)(4), but that it do so by excluding specific facilities from complying with emissions limits if the facility demonstrates that its emissions do not pose a health risk. The EPA does not believe that a plain reading of the statute supports the establishment of such an approach. Although CAA section 112(d)(4) authorizes the EPA to consider the level of the health threshold for pollutants which have an established threshold, that threshold may be considered "when establishing emissions standards under [CAA section 112(d)]." Therefore, the EPA must still establish emissions standards under CAA section 112(d) even if it chooses to exercise its discretion to consider an established health threshold. A source-by-source standard is not mandated as some commenters seem to imply, and we are unsure how we could reasonably implement such an approach even if we determined such an approach was legally available. For these reasons alone, we concluded it was not

appropriate to exercise our discretion to establish section 112(d)(4) standards for acid gas HAP emissions.

In addition, as explained in the preamble to the proposed rule, the EPA also considered the co-benefits of setting a conventional MACT standard for HCl. The EPA considered the comments received on this issue and continues to believe that the estimated co-benefits are significant and provide an additional basis for the Administrator to conclude that it is not appropriate to exercise her discretion under CAA section 112(d)(4). The EPA disagrees with the commenters who stated that it is not appropriate to consider non-HAP benefits in deciding whether to invoke CAA section 112(d)(4). Although MACT standards may directly regulate only HAP and not criteria pollutants, Congress did recognize, in the legislative history to CAA section 112(d)(4), that MACT standards would have the collateral benefit of controlling criteria pollutants as well and viewed this as an important benefit of the air toxics program. *See* S. Rep. No. 101-228, 101st Cong. 1st sess. at 172. The EPA consequently does not accept the argument that it cannot consider reductions of criteria pollutants in determining whether to take or not take certain discretionary actions, such as whether to adopt an HBEL under CAA section 112(d)(4). There appears to be no valid reason that, in situations where the EPA has discretion in what type of standard to adopt, the EPA must ignore controls which further the health and environmental outcomes at which CAA section 112(d) is fundamentally aimed because such controls not only reduce HAP emissions but emissions of other air pollutants as well. Thus, the issue being addressed is not whether to regulate non-HAP under CAA section 112(d) or whether to consider other air quality benefits in setting CAA section 112(d)(2) standards--neither of which the EPA is doing--but

rather whether EPA may exercise its discretion to regulate certain HAP based on the MACT approach and consider collateral health and environmental benefits when choosing whether to exercise that discretion. The EPA believes there is no legal principle that precludes it from doing so and commenters have not provided one.

F. Compliance Date and Reliability Issues

Comment: Multiple commenters asked that the compliance date be clearly stated as soon as possible, as well as that guidance be provided for utilities unable to comply with the stated timelines, to allow time for utilities to prepare for compliance. Commenters also asked that any decisions or policies on extensions be published in a rulemaking. In addition, commenters requested that the EPA establish, streamline, and simplify the process of applying for the 1-year extension under CAA section 112(i)(3).

Multiple commenters offered suggestions on methods for allowing more time for compliance, including EPA's authority under CAA section 112(n)(1)(A); state authority under CAA section 112(i)(3); Presidential authority under CAA section 112(i)(4); categorical extensions for publicly-owned or governmental facilities according to EO 13132, 13563, and UMRA of 1995; state-designed programs under the delegation provisions of CAA section 112; various Consent Decrees; Administrative Orders of Consent (AOCs); temporary waiver mechanisms; and adoption of MACT compliance schedules through minor permit modifications of a source's Title V federal operating permits. Absent such considerations for additional compliance time, many commenters suggested that the reliability of the nation's electric grid would be jeopardized as utility companies were forced to retire EGUs because

they could not install the needed controls in the requisite time.

Compliance times requested by commenters ranged from 1 additional year (4 years total) to 6 additional years (9 years total). Multiple commenters requested that a utility be required to demonstrate good faith progress toward compliance to get any extension. Some commenters suggested that the EPA require utilities to submit a notice concerning which EGUs will be retrofitted or retired within 1 year of the effective date; that the compliance date align with the Power Year used by RTOs; and that the EPA clarify that retirement and any clean replacement power that complies with the NESHAP rule, including off-site combined heat and power and waste heat recovery, can be deemed "controls" under the CAA.

Commenters noted the specific situations related to small entities and their inability to compete with the larger, investor-owned utilities for financing and engineering and technical labor as well as the different process they need to follow for capital improvements. Multiple commenters asked that the EPA consider other simultaneous rulemakings (*e.g.*, Cooling Water Intake Structures; Coal Combustion Residuals; CSAPR, etc.) and extend the compliance period. Many commenters noted these other requirements and suggested that installation of the necessary controls could not be completed within the compliance period allowed under CAA section 112, even if a fourth year were to be granted by the permitting authority, citing examples of the times necessary for installation of various pieces of control equipment or replacement power.

Some commenters pointed to existing state programs (*e.g.*, Colorado, Oregon, Washington) and

indicated that if states can demonstrate that overall emissions reductions would be equivalent or greater than those that would be achieved by the proposed rule, the EPA should delegate the CAA section 112 program to these states, even if the state emissions reductions would not necessarily occur on the same schedule (many state programs call for retirement of EGUs in years beyond the CAA section 112 compliance date). The commenters did not want the promulgation of the final rule to undermine the significant amount of work that may have been invested in creating state-specific programs to curb emissions within a reasonable timeframe. The commenters seek to make use of temporal flexibility, authorized under CAA section 112(i)(3), in obtaining delegation of the final rule to preserve the hard-negotiated comprehensive state-specific programs designed to yield greater emission reductions than the MATS alone.

Other commenters requested that no additional time be granted for compliance. These commenters reference a number of reports (*e.g.*, by the UPS Corporation, by M.J. Bradley & Associates and the Analysis Group, and by the Bipartisan Policy Center) to indicate that not only is technology readily available, but that the technology can typically be installed in less than 2 years and that the electric industry is well-positioned to comply with the EPA's proposed air regulations without threatening electric system reliability. Commenters assert that, if electric system reliability were to be threatened in local areas as a result of the rule, the EPA has the statutory authority to grant, on a case-by-case basis, extensions of time to complete the installation of pollution control systems. One commenter stated that no additional controls would need to be installed in many cases and any coal unit should be able to comply with all of the

standards. Another commenter noted that utilities that failed to plan ahead "should not be permitted to use their own inaction to justify more time." Commenters noted that several major utility companies have anticipated the EPA's rules and are already taking action to ensure a reliable supply of electricity in their service territory and beyond. Other commenters agree that there is significant excess generation capacity in the country and reliability will not be threatened by the rule. According to one commenter, companies are already preparing for a 2015 compliance date, factoring in the capital expenditures required to comply and delays would undermine decisions that have already been made. Commenters cite, for example, recent electricity forward capacity market auctions in the PJM market for the period of 2014 and 2015 that indicate that the capacity markets cleared with electricity reserve margins of 20 percent; this is in excess of the default reliability targets used by the North American Electric Reliability Corporation (NERC) for the year 2015. One commenter quoted NERC, stating that NERC does not see impacts from proposed climate legislation or anticipated EPA regulation as a reliability concern. Another commenter noted that the Building and Construction Division of the AFL-CIO has stated that there is no evidence to suggest that the availability of skilled manpower will constrain pollution control technology installation. In fact, according to the commenter, given the high levels of unemployment in the construction sector, these jobs are much needed.

A number of commenters expressed concern that the time frame for compliance with a regulation under CAA section 112(d) was too short for this industry and would result in compromising the reliability of electricity supply. Commenters asserted that reliability

would be compromised in several ways: (1) EGUs might have to temporarily close if the owner or operator is unable to install controls on the unit within the 3-year time frame or 3 years plus one; (2) the timing of outages to install controls will cause short term closures that could threaten grid stability; (3) owner/operators may shut down EGUs rather than invest in retrofits to keep them running and that these closures may cause a loss of critical generation; and (4) the construction of replacement generation or implementation of other measures to address reliability concerns due to plant retirements could take longer than 3 years, and that units slated for closure may be necessary beyond the 3-year compliance period but will be unable to run because they have not installed the necessary controls.

Response: Clean Air Act section 112 specifies the dates by which affected sources must comply with this rule. New or reconstructed units must be in compliance immediately upon startup or the effective date of this rule, whichever is later. Existing sources may be provided up to 3 years after the effective date to comply with the final rule; if an existing source is unable to comply within 3 years, a permitting authority has the ability to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls.

As is explained earlier in this preamble, the 3-year compliance window is based on the date that is 60 days after publication of this rule in the **Federal Register** Because publication doesn't occur until several weeks after the rule is signed by the Administrator, the earliest required date for compliance would be sometime in March 2015. Because the last stage of

control installations usually needs to occur when the unit is off-line and because scheduled outages are usually scheduled for the spring or fall months when peak electric demand is lower, this additional time is significant as it provides companies an additional outage period, the spring of 2015, to install controls.

The EPA has considered the concerns raised by commenters and has concluded that given the flexibilities further detailed in this section, the requirements of the final rule for existing sources can be met by most sources without adversely impacting electric reliability. In particular, EPA believes that the flexibility of permitting authorities to allow a fourth year for compliance should be available in a broad range of situations (as discussed below), and that this flexibility addresses many of the concerns that have been raised. Furthermore as indicated below, in the event that an isolated, localized concern were to emerge that could not be addressed solely through the 1-year extension under CAA section 112(i)(3), the CAA provides flexibilities to bring sources into compliance while maintaining reliability.

The EPA considered the impact that potential retirements in response to this rule will have on resource adequacy in order to gauge the rule's impact on reliability. In considering these impacts, the EPA considered both the analysis it has conducted as well as analyses conducted by a number of other groups. The EPA's analysis shows that the expected retirements of coal-fueled units as a result of this final rule (4.7 GW) are fewer than was estimated at proposal and much fewer than some have predicted.[321]

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[321] The EPA's analysis also identifies a small amount of capacity loss (less than 0.7 GW) due to derating of certain units, as well as partially offsetting reductions in non-coal retirements

The net capacity reductions projected by the EPA make up less than one-half of one percent of the total generating capacity in the U.S. and about one and one-half percent of U.S. coal capacity. Because concerns have been raised that the use of DSI may not be as prevalent as the Agency has predicted and because this could lead to more coal retirements, the Agency also performed a sensitivity analysis in which fewer DSI systems and more scrubber systems were installed. In that sensitivity, we see approximately 1 more GW of retirements. This small change would have only a very small potential impact on resource adequacy. When considering the impact that one specific action has on power plant retirements, it is important to understand that the economics that drive retirements are based on multiple factors including: expected demand for electricity, the cost of alternative generation, and the cost of continuing to generate using an existing unit. The EPA's analysis shows that the lower cost of alternative fuels, particularly natural gas, as well as reductions in demand, will have a greater impact on the number of projected retirements than will the impact of this final rule.

The EPA's assessment looked at the capacity reserve margins in each of 32 subregions in the continental U.S. Demand forecasts used were based on EIA projected demand growth. The analysis shows that with the addition of very little new capacity, average reserve margins are significantly higher than required. The NERC assumes a default reserve margin of 15 percent while the average capacity margin seen after implementation of the policy is nearly 25

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in comparison with the base case. The net estimated reduction in capacity, in comparison with the base case, is estimated at less than 5 GW.

percent. Although such an analysis does not address the potential for more localized reliability concerns associated with transmission constraints or the provision of location-specific ancillary services (such as voltage support and black start service), the number of retirements projected suggests that the magnitude of any local reliability concerns should be manageable with existing tools and processes.

Several outside analyses have reached conclusions consistent with EPA's analysis. The DOE, in December 2011, published a report that looked at resource adequacy in the bulk power system when faced with a stress test which was a regulatory scenario far more stringent than EPA's regulations.[322] For this stress test, in addition to CSAPR and MATS requirements, each uncontrolled electric generator is required to install both a wet FGD system and a fabric filter to reduce air toxics emissions. If such installations are not economically justified, this scenario assumes that the plant must retire by 2015. In reality, as discussed previously, power plant owners will have multiple other technology options to comply with the regulations--options that typically cost less than installations of FGDs and fabric filters. The analysis finds that target reserve margins can be met in all regions, even under these stringent assumptions. Moreover, in every region but one (TRE), no additional new capacity is needed. In TRE, the analysis finds that less than 1 GW of new natural gas capacity would be needed by 2015 beyond the additions already projected to occur in the Reference Case. This analysis also finds that the total amount of new capacity that would be

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[322] U.S. Department of Energy, December 2011, "Resource Adequacy Implications of Forthcoming EPA Air Quality Regulations."

added by 2015 is less than the amount that is already under development.

In June 2011, the Bipartisan Policy Center issued a report analyzing potential collective impacts of EPA's pending power sector rules and concluding that "scenarios in which electric system reliability is broadly affected are unlikely to occur."[323]

In August 2011, PJM Interconnection--the Regional Transmission Operator (RTO) responsible for planning and reliable operation of the bulk power system serving all or portions of 13 states in the Mid-Atlantic and Midwestern regions--issued a report analyzing the impacts of the CSAPR and the proposed MATS rule.[324] Although PJM's analysis assumes substantially more retirements than EPA projects, it nevertheless concludes that resource adequacy is not threatened in the PJM region. This is particularly significant, given that the PJM region is one of the largest and most heavily dependent on coal-fueled generation in the country. The PJM analysis notes, as EPA has acknowledged, that even where there is adequate generation capacity on a regional basis, localized reliability issues may emerge in connection with retirements that may need to be addressed.

The EPA has reviewed industry and NERC studies suggesting, contrary to the EPA's and these other groups' analyses, that EPA rules affecting the power sector (including this final rule, the CSAPR, EPA's

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[323] Bipartisan Policy Center, June 2011, "Environmental Regulation and Electric System Reliability."

[324] PJM Interconnection, August 26, 2011, "Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants."

proposed rule addressing power plant cooling water intake systems under section 316(b) of the Clean Water Act (CWA), and EPA's proposed rule addressing coal combustion residuals under the Resource Conservation and Recovery Act) will result in substantial power plant retirements. Some of these studies predict that such levels of retirements will have adverse effects on electric reliability in some regions of the country. Although the specifics of these analyses differ, in general they share a number of serious flaws in common that call their conclusions into question.

First, most of these studies make assumptions about the requirements of the EPA rules that are inconsistent with, and dramatically more expensive than, the EPA's actual proposals or final rules. For example, a large proportion of the retirements projected by several of these studies is attributable to their inaccurate assumption that EPA's cooling water intake rule under CWA section 316(b) would require all or virtually all existing power plants to install cooling towers. In one study, the reliability effects reported are based on inaccurate assumptions that all existing EGUs with a capacity utilization factor of less than 35 percent would close, and that all in-scope electric generators would be required to install cooling towers within 5 years, whereas the not-selected options with closed cycle cooling in EPA's proposal envisioned that permit authorities could exercise discretion to allow facilities 10 to 15 years' time to comply. In most cases, these analyses were performed before the CWA section 316(b) rule or the MATS rule were even proposed; even analyses subsequent to the CWA section 316(b) proposal continue to inaccurately portray EPA's proposed approach.

Second, in reporting the number of retirements, many analyses fail to differentiate between plant retirements attributable to the EPA rules and retirements of older, smaller, and less efficient plants that are already scheduled for retirement because owners have made business decisions, based in significant part on market conditions, not to continue operating them.

Third, most of these analyses fail to account for the broad range of responses available to address electric reliability concerns associated with power plant retirements, including upgrades to the transmission system, construction of new generation, and implementation of demand-side measures. These measures are discussed at greater length below.

As a preliminary matter, none of these situations, either alone or in combination, will necessarily lead to an electric reliability problem. There is excess generating capacity in the U.S. today and in most cases an EGU that closes, either temporarily until it comes into compliance or permanently, will not cause a reliability problem. As explained above, our modeling of the impact of this final rule at the regional level projects retirements of less than one percent of nationwide generating capacity and confirms that there will continue to be adequate capacity in all 32 subregions of the country as sources comply with the rule.[325] This analysis shows that significantly less capacity will close in response to the final rule than might have under the proposal. Moreover, the regional modeling of retirements demonstrates that plants that

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[325] *See* Technical Support Document on Resource Adequacy in this Docket.

close in response to this rule are spread out across the country rather than clustered in one area.

Outside analyses have identified many of the same flaws in studies projecting large-scale retirements as a result of EPA's power sector rules. For example, on August 8, 2011, the Congressional Research Service (CRS)[326] issued a report concluded that studies that assert that EPA rules will cause reliability problems, often make assumptions about the requirements of the rules that are inconsistent with, and dramatically more expensive than, the EPA's actual proposals. The CRS further noted that EPA's rules will primarily affect units that are more than 40-years old, that have not yet installed state-of-the-art pollution controls, and that are inefficient. Many of these plants are being replaced by combined cycle natural gas plants, driven more my lower gas prices than by EPA's regulations. The June 2011 Bipartisan Policy Center report referenced above likewise highlighted many of these same shortcomings in the studies in question.[327]

Although we do not expect to see any regional reliability problems, we acknowledge that there could be localized reliability issues in some areas--due to transmission constraints or location-specific ancillary services provided by retiring generation--if utilities and other entities with responsibility for maintaining electric reliability do not take actions to mitigate such issues in a timely fashion. There are many potential actions that could be taken to address this problem

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[326] James E. McCarthy and Claudia Copeland, Congressional Research Service, August 8, 2011, "EPA's Regulation of Coal-Fired Power: Is a Train Wreck' Coming?"

[327] Bipartisan Policy Center, June 2011, "Environmental Regulation and Electric System Reliability."

and multiple safeguards to assure a reliable electricity supply.

First, utilities can help to assure reliability through proactive steps in coordination with relevant planning and regulatory authorities. As we said in the proposal, early planning is key. The industry has adequate resources to install the necessary controls and develop the new capacity that may be required within the compliance time provided for in the final rule.[328] Although there are a significant number of controls that need to be installed across the industry, with proper planning, we believe that the compliance schedule established by the CAA can be met. Many companies have begun to do the detailed analysis and engineering and are ahead of others in their compliance strategy. There are already tools in place (such as integrated resource planning, and in some cases, forward auctions for future generating capacity) that ensure that companies adequately plan for, and markets are responsive to, future requirements such as this final rule.

Second, companies that intend to retire EGUs should formally notify their RTO (or comparable planning authority in the case of non-RTO regions), state regulatory agencies, and regional reliability entities as soon as possible of their compliance plans, particularly with regard to any planned unit retirements. As we said before, in most places a closing plant will not be a cause for concern for reliability. The same is true of any outages required for retrofitting of units with controls. To the extent there is concern, however, early notification will provide an opportunity

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[328] As stated above, EPA has provided the maximum compliance time authorized under CAA section 112(i)(3)(A).

for transmission planners, market participants, and state authorities to develop solutions to avoid a reliability problem. In RTOs with forward capacity markets, owner/operators that do not bid generating capacity that they plan to shut down will provide an advance signal to market participants to take action to assure adequate future capacity. In all regions, early and public notification will allow market participants, planning coordinators and state authorities, as appropriate and in a timely fashion, to bring new generation on line, put demand side resources in place, and/or complete any transmission upgrades needed to circumvent a potential issue. Most RTOs only require 45 to 120 days notification of closure. In combined comments to EPA, 5 RTOs suggested that such notification should be made no later than 12 months after this regulation is final in order to allow a smooth transitioning to action to avoid a reliability problem. The EPA strongly encourages sources to provide notice to the RTOs as early as possible and believes that responsible owner/operators should and will do the early planning for compliance and provide early notification of their compliance plans, especially where such plans include retiring one or more units.

On the supply side, there are a range of options including the development of more centralized power resources (either base-load or peaking) and/or the development of cogeneration or distributed generation. Even with the current large reserve margins, there are companies ready to implement supply-side projects quickly. For instance, in the PJM region, there are over 11,600 MW of capacity that have completed feasibility and impact studies; the units representing this capacity could be on-line by the third

quarter of 2014.[329] The EPA notes, as well, that in the 3 years from 2001 to 2003, industry brought over 160 GW of generation on line.[330]

Demand side options include energy efficiency as well as demand response programs. These types of resources can also be developed very quickly. In 2006, PJM had less than 2,000 MWs of capacity in demand side resources. Within 4 years this capacity nearly quadrupled to almost 8,000 MW of capacity.[331] In addition to helping address reliability concerns, reducing demand through mechanisms such as energy efficiency and demand side management practices has many other benefits. It can reduce the cost of compliance and has collateral air quality benefits by reducing emissions in periods where there are peak air quality concerns.

With regard to transmission, recent experience also shows that, in many cases, transmission upgrades to address reliability issues from plant closures can be implemented in less than 3 years. For instance, when Exelon notified PJM of its intention to retire four units,[332] it was determined that transmission upgrades necessary to allow retirement of two units

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[329] Paul M Sotkiewicz, PJM Interconnection, Presentation at the Bipartisan Policy Commission Workshop Series on Environmental Regulation and Electric System Reliability, Workshop 3: Local, State, Regional and Federal Solutions, January 19, 2011, Washington, DC, *http://www.bipartisanpolicy.org/sites/default/files/Paul%20Sotkiewicz-%20Panel%202_0.pdf,* slide 6.

[330] Form EIA-860 Annual Electric Generator Report, *http://www.eia.gov/cneaf/electricity/page/eia860.html.*

[331] BPC slides cited above--slide 5.

[332] *http://www.exeloncorp.com/Newsroom/pages/pr_20091202_Generation.aspx?k=eddystone.*

could be made within 6 months of notification, transmission upgrades for the third unit would require slightly over 1 year and transmission upgrades to allow the fourth unit to retire could be made in approximately 18 months.[333]

The CAA allows CAA Title V permitting authorities the discretion to grant extensions to the compliance time of up to one year if needed for installation of controls. *See* CAA section 112(i)(3)(B)). If an existing source is unable, despite best efforts, to comply within 3 years, a permitting authority has the discretion to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls. Id. Permitting authorities should be familiar with the operation of the 1-year extension provision because EPA has established regulations to implement the provision and the provision applies to all NESHAP. *See 40 CFR 63.6(i)(4)(A).*

We believe that the permitting authorities have the discretion to use this extension authority to address a range of situations in which installation schedules may take more than 3 years including: staggering installations for reliability reasons or other site-specific challenges that may arise related to source-specific construction, permitting, or labor, procurement or resource challenges. Staggered installation allows companies to schedule outages at multiple units so that reliable power can be provided during these outage periods. It can also be helpful for particularly complex retrofits (*e.g.*, when controls for one unit need to be located in an open area needed to

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[333] Cromby Units 1 and 2 and Eddystone Units 1 and 2--Deactivation Study, Updated September 7, 2010--*http://policyintegrity.org/documents/20100907-cromby-and-eddystone-retirement-study-posting-update.pdf.*

construct controls on another unit). The additional 1-year extension would provide an additional two shoulder periods (*i.e.*, seasons flanking annual high-demand periods) to schedule outages, thus enabling owners/operators to gain the full benefit of staggering outages in support of complex installations. The EPA believes that although most units will be able to fully comply within 3 years, the fourth year that permitting authorities are allowed to grant for installation of controls is an important flexibility that will address situations where an extra year is necessary. That fourth year should be broadly available to enable a facility owner to install controls within 4 years if the 3-year time frame is inadequate for completing the installation.

As we indicated at proposal, this source category is unique due to the large, complex and interconnected nature of electrical generation, transmission and distribution, and the critical role of the electric grid in the functioning of all aspects of the economy. The grid functions as an interconnected system that supplies electricity to end users on a continuous basis. Safe, reliable operation of the grid requires coordination among actions taken at individual units, including timing of outages for the installation of controls, derating, or deactivation. It was for this reason that we specifically addressed in the proposed rule reasonable interpretations of the phrase "installation of controls" in CAA section 112(i)(3)(B). We determined that it was important to provide Title V permit authorities with information that might be useful if they were asked to authorize a fourth year for specific EGUs.

The EPA took comment on whether the construction of on-site replacement power could be considered the

"installation of controls" such that a fourth year would be available while the replacement unit is being completed for a unit that is retiring (*e.g.*, a case when a coal-fueled unit is being shut down and the capacity is being replaced on-site by another cleaner unit such as a combined cycle or simple cycle gas turbine). After reviewing the comments, EPA believes that it is reasonable for permit authorities to allow the fourth year extension to apply to the installation of replacement power at the site of the facility. The EPA believes that building replacement power constitutes the "installation of controls" at a facility to meet the regulatory requirements.

Commenters were generally supportive of the proposed approach described above, but a number of commenters suggested several additional situations that should be considered as the "installation of controls" such that it would be appropriate for permitting authorities to grant a 1-year extension beyond the 3-year compliance time-frame. In particular, commenters suggested that the 1-year extension should be available for a unit if a company's compliance choice was to retire that unit but doing so within the 3-year time-frame caused reliability problems for any of the following reasons: (1) Generation from the retiring unit is needed to maintain reliability while other units install emission controls; (2) new off-site generation was being built to replace the retiring unit, but the new generation was not scheduled to be operational within the 3-year time-frame and any gap between the time the existing unit retires and the new unit comes on line would cause reliability problems; and (3) transmission upgrades were needed in order to maintain electric reliability after the unit retired but could not be completed within 3 years.

While the ultimate discretion to provide a 1-year extension lies with the permitting authority, EPA believes that all three of these cases may provide reasonable justification for granting the 1-year extension if the permitting authority determines, for example, based on information from the RTO or other planning authority or other entities with relevant expertise, that continued operation of a particular unit slated for retirement for some or all of the additional year is necessary to avoid a serious risk to electric reliability.

In a case where pollution controls are being installed, or onsite replacement power is being constructed to allow for retirement of older, under-controlled generation, a determination that an extra year is necessary for compliance should be relatively straightforward. In order to install controls, companies will have to go through a number of steps fairly early in the process including obtaining necessary building and environmental permits and hiring contractors to perform the construction of the emission controls or replacement power. This should provide sufficient information for a permitting authority to determine that emission controls are being installed or that replacement power is being constructed. Because companies will need to develop this information early in the process and because a determination can easily be made as to whether the schedule will exceed 3 years, the EPA believes that Title V permitting authorities should be able to quickly make determinations as to when extensions are appropriate.

In the three cases related to retirement of a unit without construction of onsite replacement power, additional information is needed. The Title V permitting authority should request that the affected

company or companies provide information, including, for example, from the RTO or other planning authority for the relevant region, the state electric regulatory agency, NERC or its regional entities, and/or FERC or the DOE, demonstrating that retirement of a particular unit within the 3-year compliance period would result in a serious risk to electric reliability.

The first two situations involving a retiring unit--where one or more related existing units are upgrading pollution controls or a new unit is being constructed off-site--are similar to the situation we discussed in the proposed rule wherein a retiring unit at a facility runs an additional year while a replacement unit on the same site is constructed. In each of these situations, the retiring unit would be allowed to run so a unit compliant with the rule (either a retrofitted existing unit or a new unit) can come on line. We believe that these situations may, in the appropriate circumstances, constitute ones in which a 1-year extension for the retiring unit is "necessary for the installation of controls." In these two situations, however, we believe that it would be appropriate for the Title V permitting authority to consider reliability concerns as a necessary factor before granting the additional year because continuing operation of the retiring unit is only "necessary" to the extent it is required for reliability. In each of these situations, the permitting authority should determine that the retiring unit is necessary to maintain reliability until the new unit comes on line or the other existing unit is retrofitted. Title V permitting authorities may determine that multiple retiring units are available to maintain reliability, but unless all the units are necessary to address the issue, it would likely be unreasonable to provide the additional year for all the identified units.

The third hypothetical situation identified above is one in which transmission upgrades are necessary to address a reliability issue resulting from the retirement of a unit in order to comply with this rule, where the upgrade cannot be completed by the 3-year compliance date. In terms of the functionality of the electric grid, this situation has some similarity to those discussed above. Here, it is the completion of the transmission upgrades, rather than bringing another compliant (retrofitted or new) unit on line, that would allow the retiring unit to come into compliance (by retiring) without threatening reliability. The general objective and result is similar: Reductions of the existing unit's HAP emissions (through retirement) while maintaining electric reliability. If such situations develop and the reliability problem has been properly demonstrated, permitting authorities should consider whether an extension under CAA section 112(i)(3)(B) may be provided.

The EPA continues to believe, based on the analysis discussed at the beginning of this section, that most, if not all, units will be able to comply with the requirements of this rule within 3 years. The EPA also believes that making it clear that permitting authorities have the authority to grant a 1-year compliance extension where necessary, in the range of situations described above, addresses many of the other concerns that commenters have raised. The EPA believes that the number of cases in which a unit is reliability critical and in which it is not possible to either install controls on the unit or mitigate the reliability issue through construction of new generation, transmission upgrades, or demand-side measures, within 4 years, is likely to be very small or nonexistent. This view is consistent with statements from commenters explicitly mandated with ensuring grid reliability.

The EPA's authority to provide relief from the requirements of this final rule beyond the fourth year is limited by the statute. If reliability issues do develop, however, the CAA provides mechanisms for sources to come into compliance while maintaining electric reliability. One area where the EPA has some measure of flexibility is with respect to the exercise of its enforcement authorities. The Agency has used such authority in the past to bring sources into compliance with the requirements of the CAA while maintaining electric reliability, although these authorities are not as flexible as suggested by some commenters.

The EPA generally does not speak publicly to the intended scope of its enforcement efforts, particularly well in advance of the date when a violation may occur. In light of the importance of ensuring electric reliability, however, the Office of Enforcement and Compliance Assurance will separately publish a document that articulates our intended approach with respect to sources that operate in noncompliance with this final rule to address a specific and documented reliability concerns.

That document provides a pathway for reliability critical units (as such units are described in the document) to achieve compliance within an additional year. The result is that qualifying reliability critical units may come into compliance within up to 5 years. This pathway is structured to maintain reliability, to ensure CAA compliance and to increase certainty for sources in planning by allowing a unit owner/operator to determine whether it qualifies for a compliance schedule well in advance of the MATS compliance deadline.

The EPA believes that there will be few, if any, situations in which it will be necessary to have recourse

to the processes discussed in the document just described, and that there are likely to be fewer, if any, cases in which it is not possible to mitigate a reliability issue within the further year contemplated under that document. However, there is always the possibility that some unit owner/operator will be unable to address its reliability issues within 5 years and there is always the possibility that a unit owner/operator will be unable to timely comply with the MATS for some other reason. Consistent with its longstanding historical practice under the CAA, the EPA will address individual non-compliance circumstances on a case-by-case basis, at the appropriate time, to determine the appropriate response and resolution.

A number of commenters also raised concerns about inconsistencies between the compliance timelines under this final rule and existing state agreements with specific owners/operators to install pollution control equipment and/or retire EGUs. The EPA believes the flexibilities provided in this discussion allow for some discretion to address those cases, but that they may not be fully addressed. The EPA is supportive of such efforts and believes they can have important multi-pollutant health and environmental benefits. To the extent that the flexibilities discussed here do not fully address a particular situation, we encourage states and sources to contact the EPA as early as possible to discuss their individual circumstances.

G. Cost and Technology Basis Issues

1. Dry Sorbent Injection

Comment: Several commenters stated that there is limited commercial operating experience in using DSI to control acid gas emissions from coal-fired boilers.

They suggest that the technology is not adequately proven for use in this application.

Other commenters disagree with statements made that DSI is not proven. One commenter stated that DSI is a mature technology. The commenter indicated that DSI is well suited for units that burn fuels with lower or mid-level sulfur contents, and is among the viable options available for a number of sources to achieve the proposed HCl limits. Thus, the commenter believes that DSI represents a real technology control option for many units, and is among the suite of technology options that certain units will be able to employ to meet the proposed HCl limit.

Response: As explained in this response and elsewhere in this preamble, the EPA agrees that DSI technology is proven and ready for commercial use in controlling acid gases from coal combustion. One of the largest coal-burning electric utilities in the U.S, American Electric Power (AEP), pioneered the practical use of DSI with trona, a sodium-based sorbent, for SO_3 mitigation. American Electric Power has implemented trona injection for that purpose across its entire bituminous coal-fired fleet where both SCR and wet FGD systems are in place.[334] Examples of coal-fired EGUs already using trona DSI to control SO_2 emissions include NRG Energy's Dunkirk Generating Station Units 1-4 and CR Huntley Units 67 and 68 in New York.[335] The Dunkirk units range in

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[334] *SO<3> Control: AEP Pioneers and Refines Trona Injection Process for SO<3> Mitigation,* Coal Power, March 2007, *http://www.coalpowermag.com/plant_design/SO3-Control-AEP-Pioneers-and-Refines-Trona-Injection-Process-for-SO3-Mitigation_29.html.*

[335] NRG Energy letter to RGGI, Inc, November 22, 2010, *http://www.rggi.org/docs/NRG_Nov_2010.pdf.*

size from 75 MW to 190 MW. Much larger units may also be economic when using DSI for SO_2 control, as suggested by Dominion Energy's studies of adding DSI on two 625 MW units at the Kincaid plant in Illinois.[336] One of the largest suppliers of air emission control systems in the world, vouches that DSI is commercially proven for acid gas control:[337] [338]

Comment: Numerous comments were received on EPA's IPM modeling of DSI in the MATS analysis. A few commenters stated that DSI will not work on bituminous coals. Some commenters stated that DSI is only suitable for use on low sulfur, low chlorine western coals. Others stated that DSI is only likely to be used on relatively small units, and that larger units would use scrubbers for acid gas control. Several commenters expressed the opinion that because there is little commercial operating experience in using DSI to control SO_2 emissions from coal-fired boilers, EPA's IPM modeling assumptions on the efficacy and cost of the DSI control option are unjustifiably optimistic. Some commenters believe that DSI will not be as economic or as widely applicable for either SO_2 or HCl control as projected by EPA's IPM modeling. Commenters observe that wet or dry scrubbers for FGD, longer-standing control technologies for SO_2 and HCl, are more complex systems with a much higher capital cost than DSI. These commenters argue that

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[336] Dominion Energy, *BART Analysis for the Kincaid Power Plant*, January 2009, *http://www.epa.state.il.us/air/drafts/regional-haze/bart-kincaid.pdf.*

[337] Dry Sorbent Injection Systems for Acid Gas Control, Babcock & Wilcox, 2010, *http://www.babcock.com/library/pdf/ps-451.pdf.*

[338] Technologies for Acid Gas Control, Babcck & Wilcox, 2011, *http://www.babcock.com/library/pdf/ps-457.pdf.*

the sector will need to retrofit many more FGD scrubbers than projected by IPM for MATS compliance and will therefore experience a much higher overall cost of compliance than projected by IPM, as well as needing more time and resources for retrofit construction. A few commenters suggested that EPA should base its MATS modeling on this more conservative outlook. A few commenters were concerned that EPA's DSI modeling assumptions relied on performance data from only one DSI vendor.

Some commenters were concerned that fly ash currently sold for beneficial uses will become unsalable because it will be contaminated by injected sodium-based DSI sorbents. Two commenters argued that EPA's IPM analysis understates DSI cost by not including the costs of foregone fly ash sales revenue and contaminated fly ash disposal. A few commenters observed that landfilling of sodium-based DSI solid wastes will produce leachate containing sodium and other compounds that are challenging to handle, thus requiring special landfill designs and a high cost for landfill disposal of DSI waste.

Response: The EPA believes that its representation of DSI in MATS compliance modeling is reasonable, is properly limited to applications that are technically feasible, and reflects a conservative approach to modeling future use of this technology.

The EPA disagrees that its IPM modeling of DSI is overly optimistic and therefore underestimates the costs of MATS compliance. In its IPM modeling, EPA restricts the availability of the DSI option to only those units that use or switch to relatively low sulfur coal: Less than 2 lb SO_2 /MMBtu (*See* IPM documentation in the docket). The EPA's IPM projections for MATS compliance, therefore, already include the costs of any

additional FGD scrubbers that are economically justified and projected for use on units using higher sulfur coals. The EPA models DSI assuming fine-milled trona as the injected sorbent. As mentioned by several commenters, sodium bicarbonate (SBC), which is processed from trona, is also suitable for use with DSI. Sodium bicarbonate is more reactive with acid gases than trona. It would require less tonnage of sorbent and less tonnage of waste disposal than trona for the same SO_2 removal effect, albeit at somewhat higher sorbent cost. Non-sodium based sorbents such as hydrated lime (calcium based) could also be used. Therefore, EPA's modeling of DSI technology does not include the full spectrum of sorbent choices that real-world applications enjoy, meaning that there may be opportunities for lower-cost applications of DSI that are not captured in EPA's projections for MATS. The EPA models DSI with trona injection rates corresponding to 70 percent SO_2 removal for all coals, assuming that an equivalent amount of sorbent is needed to provide 90 percent HCl removal, regardless of the low sulfur and chlorine content of western coals.

Senior technical staff from the EPA have carefully evaluated the key assumptions regarding the cost and operation of emission control technologies. In general, these staff believe that trona should have strong HCl reaction selectivity and, consequently, EPA's assumed trona injection rates may be overstated. The extent to which this assumption may actually overstate DSI control costs can be observed through DSI pilot testing for Solvay Chemicals by the Energy & Environmental Research Center (EERC) at the University of North Dakota.[339] The EERC's testing of trona DSI on a

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[339] Solvay Chemicals, Inc., HCl Removal in the Presence of SO_2 Using Dry Sodium Sorbent Injection, *http://www.solvair.us/*

central Appalachian bituminous coal (1.3 lb SO_2 /MMBtu) substantiates the strong HCl reaction selectivity of sodium-based sorbents, including trona, and calcium-based hydrated lime. The EERC's pilot testing shows that fine-milled trona, when well mixed into 325 [degrees] F flue gas upstream of a FF, provides 90 percent HCl removal at a SO_2 removal rate of less than 20 percent (as compared to EPA's modeling assumption of aligning 90 percent HCl removal with sorbent injection designed to achieve 70 percent SO_2 removal). The data show that 95 percent or higher HCl removal is readily obtained at somewhat higher SO_2 removal rates. Similarly strong HCl selectivity results were obtained using trona and an ESP at 650 [degrees] F. Test data from United Conveyor[340] on full-scale units also show these high HCl selectivity trends. Overall, these test data from multiple major vendors suggest that even if a SO_2removal rate of 30 percent were required in order to obtain 90 percent HCl removal in the imperfectly mixed flow of a full-scale unit, it still appears that EPA's assumed trona injection rates may be as much as twice as high as would actually be needed in practice for certain applications. It is apparent that if EPA were to re-analyze MATS compliance with DSI injection rates reduced by 50 percent, there would be a corresponding reduction in the sorbent and related waste disposal costs that constitute most of the cost of using DSI.

SiteCollectionDocuments/presentations/20111214_hcl_presentation.pdf.

[340] United Conveyor Corporation, *Dry Sorbent Injection for Simultaneous SO<2> HCl, and Hg Removal*, October 2011, *http://unitedconveyor.com/uploadedFiles/Systems/Systems_Sub/McIlvaine%20Multipollutant%20Removal%20Oct%202011.pdf.*

Given the EERC test data, it is also apparent that most units that have ESPs and are burning low sulfur western coal could meet the HCl limit using DSI without the addition of a FF. If EPA were to re-analyze MATS compliance while allowing DSI use without the need for a downstream FF, it is apparent that there would be a very significant reduction in the overall number of FF retrofits projected, and a corresponding reduction in annualized capital costs. For the MATS proposal, the EPA modeled DSI on the assumption that all chlorine in coal converts to HCl, and that DSI would be the only mechanism by which the unit could prevent HCl from being emitted. Based on public comments and a more thorough review of the ICR data, the EPA has introduced in final MATS modeling a recognition that the relatively high alkalinity of ash from subbituminous and lignite coals "removes" much of the HCl that would otherwise be emitted from combustion of these particular coals. The 2010 ICR data indicate that in some cases the ash itself removes sufficient HCl from these coals for MATS compliance; in effect, these acid-gas emissions are absorbed by coal ash and are captured by particulate control devices instead of being emitted in gaseous form. As a conservative measure, EPA's revised final MATS modeling assumes that 75 percent of HCl is removed by the ash for these coals. In the event that ash capture in practice is more effective than this 75 percent assumption, then EPA's analysis projects a conservatively higher level of DSI installations (and, thus, compliance cost) than would actually occur in practice. In any case, it appears that significantly less sorbent injection would actually be required in practice than assumed by EPA for these low sulfur, low chlorine coals, and that the IPM projected DSI

operating costs are likewise higher for these coals than would be experienced in practice.

The EPA models DSI with sorbent injection occurring downstream of an existing electrostatic precipitator (ESP). The existing ESP is assumed to remain in service. The model adds a fabric filter downstream of the DSI injection point to capture the small amount of PM passing through the ESP plus the reacted and unreacted DSI sorbent. Most of the DSI projected by IPM, therefore, includes the costs of a retrofitted FF. This modeled configuration allows fly ash currently captured in ESPs to remain uncontaminated by DSI sorbent and, therefore, remain available for sale and beneficial use. The EPA conservatively models FF costs based on an assumed full-size system with an air-to-cloth ratio of 4.0. The FF costs could be somewhat less in practice if a smaller system (with an air-to-cloth ratio of 6.0) were used for the reduced DSI dust loading. The EPA observes that some of the owners of units with ESPs may chose to convert existing ESPs into FFs,[341] an option not modeled in IPM, but that would likely have a lower capital cost than a retrofitted FF. In the MATS proposal EPA modeled DSI with a waste disposal cost of $ 50/ton, based on a Sargent & Lundy DSI cost model prepared for EPA (*See* proposal IPM documentation in the docket). The EPA has continued to model DSI at this waste disposal cost for analysis of the final rule. However, recent discussions between senior technical staff from the DOE and the EPA have

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[341] TW Lugar, *et al., The Ultimate ESP Rebuild: Casing Conversion To a Pulse Jet Fabric Filter, a Case Study,* Electric Power Conference, May 2009, *http://www.cecoenviro.com/uploads/ESP%20to%20Fabric%20Filter%20Baghouse%20Conversion%20-%20Buell%20Case%20History.pdf.*

suggested that in some situations sodium sulfates, that would be formed by the injection of trona, could potentially leach out of the fly ash/sorbent mixture on contact with water. Although the technical staff recognized that these concerns are more relevant to bituminous coal-fired units where ashes are not cementitious, unless mixed with limestone or lime, they suggested that the impacts of potentially higher disposal costs be evaluated. Based on public comments, further investigations by Sargent & Lundy, and suggestions from the EPA and DOE technical staff, EPA's analysis of the final rule has included an IPM sensitivity case using a DSI waste disposal cost of $ 100/ton. The sensitivity case indicates that a 100 percent increase in assumed DSI waste disposal cost produces slightly less than a 1 percent increase in the projected cost of the rule.

Comment: A few commenters expressed the concern that there is an inadequate supply of trona to support DSI operations at the levels projected by the EPA for MATS compliance.

Response: The EPA projects that just over 50 GW of coal-fired capacity might retrofit with DSI for MATS compliance, thus reducing SO_2 emissions by about 1 million tons per year. Based on conservatively high trona injection rates, as discussed above, the EPA estimates that the amount of trona required to support DSI operations at this level is about 4 million tons per year. By comparison, the trona mining industry in the U.S. has a demonstrated production capacity of at least 18 million tons annually, and was running well

below that capacity (16.5 million tons) in 2010.[342] [343] If the EPA's assumed trona injection rates are as much as 50 percent greater than actually needed for at least 90 percent HCl control, as discussed above, and given that some subbituminous coals will apparently need little or no sorbent injection for HCl control, there may already be an adequate surplus of trona production capacity to support DSI for MATS compliance. The EPA, therefore, concludes that trona supply for DSI is either already adequate, or will require at most a small increase in production capacity.

For all of these reasons, the EPA believes that its representation of DSI in MATS compliance modeling is reasonable, is properly limited to applications that are technically feasible, and reflects a conservative approach to modeling future use of this technology.

2. Economic Hardship

a. Job Losses and Economic Impacts

Comment: Several commenters indicated that they believe the proposed rule will weaken industry, cause job losses and hurt power consumers. One commenter reported that the proposed rule will affect 1,350 coal and oil-fired units at 525 power plants and that NERC reports that by 2018 nearly 50,000 MW of capacity will be retired by the proposed rule. Many of these commenters compared the cost estimated by EPA to a variety of other sources that estimate substantially higher costs of the rule. The commenters expressed concern that electricity price increases are likely to be

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[342] *http://www.wma-minelife.com/trona/tronmine/tronmine.htm.*

[343] *http://www.wma-minelife.com/trona/TronaPage2/trona_production.htm.*

up to 24 percent in some regions as a result of the proposed rule. In addition to the economic difficulty the proposed rule could place on consumers, the commenter believes that many in the energy sector will lose their jobs due to coal-fired capacity losses. The commenters believe the effects on coal-fired plants in the Southeast especially will mean the loss of high-paying, high-skilled jobs and drastic price increases in energy costs. Additionally, commenters expressed concern that increased electricity and natural gas prices would impact businesses in multiple sectors across the country.

Response: The EPA disagrees with the estimates presented by the commenters. The EPA has updated its analysis to reflect the final MATS. The Agency estimates the annual costs of the final rule in 2015 to be $ 9.6 billion in 2007 dollars. The estimate of early retirements of coal-fired units due to this rule is 4.7 GW, lower than the level estimated at proposal. Both of these estimates were prepared using the IPM, a model that has been extensively reviewed and has been utilized in several rulemakings affecting the power generation sector over the last 15 years. The Agency's analyses are credible and accurate to the extent possible, and all assumptions and data are made public. Limitations and caveats to these analyses can be found in the RIA for this rule.

The EPA estimates that there will be an increase of 3.1 percent in retail electricity price on average in the contiguous U.S. in 2015 as an outcome of this rule, with the range of increases from 1.3 percent to 6.3 percent in regions throughout the U.S. No region of the U.S. is expected to experience a double-digit increase in retail electricity prices in 2015 or in any year later than that, according to the Agency's analysis, as a

result of this rule. To put this in context, the roughly 3 percent incremental increase in aggregate end-user electricity prices projected to occur over the next 4 years is about the same as the 3 percent absolute average change in total end-user electricity prices observed on an annual basis.[344] Furthermore, the roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[345] Even with this rule in effect, electricity prices are projected to be lower in 2015 and 2020 than they were in 2010.[346]

The Agency found that the readily discernible impact on long-term employment nationally within the most directly affected sectors should be small and the EPA also estimated that about 46,000 job-years[347] of one-time construction labor could be supported or created by this rule. This includes jobs manufacturing steel, cement and other materials needed to build pollution control equipment, jobs creating and assembling pollution control equipment, and jobs

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[344] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 to 2010, Table 8-10.

[345] Ibid, EIA AEO 2010, Table 8-10.

[346] Ibid, EIA AEO 2010, Table 8-10 for price levels; and Chapter 3 of the RIA for electricity price differential.

[347] "job-year" is a combined measure of jobs and job duration which is equivalent to one person being employed for one year. For example, 2 job-years could represent two years of employment for one worker, one year of employment for two workers, or 6 months of employment for four workers. Estimates of employment changes that involve non-permanent workers are usually reported in job years to give a sense of the total employment effects.

installing the equipment at power plants. Potential job increases from increased output by lower-emitting facilities (such as increased generation from well-controlled coal-fired plants that replace generation from older coal-fired plants) are expected to partially or fully offset potential job losses resulting from reduced output from higher-emitting facilities. The EPA analysis projects a net change in the directly affected EGU sector of between 15,000 net jobs lost to 30,000 net jobs gained on an annual basis.[348] See Chapter 6 of the RIA for further details.

The EPA has also looked at the possibility that changes in the price of electricity may influence the levels and geographic distribution of downstream economic activities, and associated employment. Projecting how potentially higher electricity prices may affect various downstream economic activities in particular regions as a result of this rule is challenging for several reasons: (1) There are significant uncertainties regarding projections of consumer- and location-specific electricity price changes in response to future firm-specific compliance strategies; (2) the availability of competitively-priced alternative energy sources (including energy conservation) and less electricity-intensive substitute goods and services may significantly mitigate potentially adverse economic consequences resulting from projected increases in electricity prices in ways which are not captured effectively in currently available models; and (3) available modeling tools are not configured to capture

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[348] It should be noted that if more labor must be used to produce a given amount of output, then this implies a decrease in labor productivity. A decrease in labor productivity will cause a short-run aggregate supply curve to shift to the left, and businesses will produce less, all other things being equal.

the effects over time of economically significant effects of cleaner air (*e.g.*, reductions in medical expenditures and improvements in labor productivity resulting from fewer lost work days) achieved by rules evaluated using single target year criteria pollutant and/or HAP benefits projections. After considering these methodological limitations, the Agency concludes that there is not a satisfactory methodology for projecting the downstream economic (including employment) effects of any changes in electricity prices due to this rule.

We expect the downstream economic effects of this rule to be small because electricity is only a small factor in the production of most goods and services.[349] A 3 percent increase in end-user electricity prices translates to a much smaller effect on prices and potential output of goods and services from end-users of electricity. Over time, the incremental effect of this rule on electricity prices is projected to diminish significantly; for example the difference in expected prices is projected to narrow from 3.1 percent in 2015 to 2.0 percent in 2020 as shown in Chapter 3 of the RIA.

Despite the absence of a satisfactory methodology for quantifying the potential economy-wide effects (including employment) of any potential increases in electricity prices resulting from this rule, the EPA expects the incremental effects of this rule on electricity prices to be small given the projected electricity price increases relative to historical levels and volatility in end-user electricity prices. Based on

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[349] BEA. (2007b). Commodity-by-Industry Direct Requirements after Redefinitions, 2002. Available in: *2002 Summary Tables, 2002 Benchmark Input-Output Data*. Retrieved from *http://www.bea.gov/industry/io_benchmark.htm#2002data*.

these projections and contextual information, the Agency believes that the incremental effects on electricity prices and economic activity of this rule are likely to be small relative to other factors influencing electricity prices, overall employment, and other aspects of economic activity.

Comment: Several commenters considered the proposed rule to be a tax on the American public, since utilities implementing upgrades will pass the costs on to the consumer. Commenters questioned the preference of Americans to subsidize renewable energy sources and put money into the proposed rule instead of other environmental programs with greater benefits. Commenters explained that the tax-like price increase reduces income of energy consumers and depresses business development. The commenters used California as an example of a state that uses low rates of coal-based electricity and cites companies that have left the state as a result of substituting higher cost forms of electricity for coal. A commenter stated that coal-derived energy will rapidly become more expensive, especially in the "rust belt" and Southeast region, as can be seen by the rate increase already requested in Louisville. A commenter believes the "indirect taxation" limits the ability of the economy to absorb the cost of retrofitting and new capacity projects, lowers discretionary spending and leads to job losses and lost tax revenues, given the restrictive timeframe for compliance.

Response: The Agency does not agree that this rule creates or alters any taxes on affected sources required under this rule to reduce their emissions of toxic air pollutants, nor are taxes created or altered or imposed on consumers of electricity which is provided to the market by affected sources. Moreover, unlike a tax,

this rule does not generate government revenue. The rule does, however, indirectly address the problem of the "externality cost" of higher health risks and other adverse effects on the populations exposed to toxic air pollution emissions from affected sources. This rule may have the effect of reducing or eliminating a market distortion that provides an implicit subsidy to affected facilities. This implicit subsidy results from the fact that some facilities currently can avoid the costs of toxic air pollution controls by imposing higher health and other costs on those who are exposed to higher levels of toxic air pollution. The Agency also disagrees with the implication that the costs incurred by less-controlled sources to bring their toxic air emissions in line with their better-controlled competitors will lead to significant or debilitating changes in market and economic conditions. The Agency's estimate of the potential increase in retail electricity price is an average of 3.1 percent in 2015, with a range of increases by region from 1.3 percent to 6.3 percent. As shown in Chapter 3 of the RIA, the higher rates of potential electricity price increase tend to occur in those regions where electricity prices have been relatively low, due to some extent to reliance on coal-fired units which have been cheaper to operate due to underinvestment in toxic air pollution controls.[350] As shown in Chapter 3 of the RIA, all regions with year 2015 projected percentage increases in retail electricity prices above the contiguous U.S. average are also projected to have baseline retail electricity prices which are below the contiguous U.S. average price level in that year. In addition, natural gas prices will only increase by 0.3 to 0.6 percent on

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350 *http://www.epa.gov/airmarkets/images/CoalControls.pdf.*

average over the time horizon of 2015 to 2030. As discussed above, for consumers of electricity in the commercial and industrial sectors, electricity tends to be a fairly small fraction of total costs of production, implying that the average projected electricity price increase of 3 percent will lead to only a small fractional change in the costs of providing goods and services to the economy. While some residential electricity consumers may similarly see a small price increase in retail electricity prices, it should be noted that these consumers tend to reside in the same area or region as the affected facility and so will also experience the improvement in air quality from the reductions due to the rule. The reduction in health risk and other improvements to quality of life associated with lower exposure to toxic and other air pollutants achieved by this rule will confer benefits on these consumers which include lower risks of premature mortality, lower morbidity, and improved productivity and competitiveness of U.S. workers due to reduction in work days lost to air pollution-related illness. The benefits of these improvements are projected to exceed costs of compliance by affected sources by at least six-fold. The potential price increases in electricity and natural gas should be considered in light of the substantial health, welfare, and economic benefits achieved by this rule.

Comment: Many commenters expressed support for the EPA's impact analysis and disputed claims by other commenters that the projected rule will harm economic growth. A number of commenters mentioned testimonials by power company CEOs stating that the proposed rule will not affect the economic health of the industry and a survey showing nearly 60 percent of the coal-fired units already comply with the EPA's proposed Hg standard, and several other meaningful quotes from utility executives. The commenters also

pointed out that 17 states already require plants to address Hg pollution, with some imposing more stringent emission limits than the EPA proposes. The commenters believe that utilities use the threat of power plant closures and lost jobs to delay Hg reductions from coal-fired plants. Commenters also believe that the rules will drive innovation and job creation as new technologies to reduce pollution are created. Several commenters quoted the Economic Policy Institute finding that the proposed rule will increase job growth by 28,000 to 158,000 jobs by 2015 (including approximately 56,000 direct jobs and 35,000 indirect jobs), the University of Massachusetts study that showed an increase 1.4 million jobs in 5 years, and the Constellation Energy Group installation project that employed nearly 1,400 skilled workers. Commenters also cited the University of Massachusetts study statement that a net gain of over 4,200 long-term operation and maintenance jobs will result.

Several commenters observed that the positive impacts of the rule strongly favor its adoption. These commenters stated that, contrary to the unfounded assertions by critics of EPA and the rule, EPA has conducted a technically sound and conservative benefit-cost analysis showing that the proposed rule's estimated benefits are at least five times as high as its costs. One commenter stated, "With sound, albeit unduly conservative, econometric modeling, EPA has also determined that the Toxics Rule will promote economic growth and create jobs in both the long and short term." Two commenters cited the EPA impact analyses by Dr. Charles Cicchetti which confirm this finding and state that the analysis underestimates the rule's net benefits and positive impacts on the nation's economy. By considering some benefits not monetized

in the EPA analysis, Dr. Cicchetti concludes that the proposed rule will create $ 52.5 to $ 139.5 billion in net benefits annually, create 115,200 jobs, generate annual health savings of $ 4.513 billion, annual increases in GDP of $ 7.17 billion and $ 2.689 billion in additional annual tax revenues, and spur innovation and modernization of EGUs. The commenters state that the study findings show no need to delay implementation of the rule or needlessly duplicate economic analyses already completed.

Commenters reported that multiple researchers confirmed that the EPA's estimates of economic stimulus are conservative and that the proposed rule will stimulate job growth. A commenter quotes Dr. Josh Bivens of the Economic Policy Institute, who also found that EPA's conclusions were conservative. Dr. Bivens concluded, "The EPA RIA on the proposed toxics rule makes a compelling case that the rule passes any reasonable cost-benefit analysis with flying colors--the monetized benefits of longer lives, better health, and greater productivity dwarf the projected costs of compliance * * * Whether regulation in general and the toxics rule in particular costs jobs is an empirical question this paper attempts to answer. In particular, this paper examines the possible channels through which the proposed toxics rule could affect employment in the United States and finds that claims that this regulation destroys jobs are flat wrong: "The jobs-impact of the rule will be modest, but it will be positive." His report details the following major findings:

1. The proposed rule would have a modest positive net impact on overall employment, likely leading to the creation of 28,000 to 158,000 jobs between now and 2015.

2. The employment effect of the [MATS] on the utility industry itself could range from 17,000 jobs lost to 35,000 jobs gained.

3. The proposed rule would create between 81,000 and 101,000 jobs in the pollution abatement and control industry (which includes suppliers such as steelmakers).

4. Between 31,000 and 46,000 jobs would be lost due to higher energy prices leading to reductions in output.

5. Assuming a re-spending multiplier of 0.5, and since the net impact of the above impacts is positive, another 9,000 to 53,000 jobs would be created through re-spending.

Response: The EPA thanks the commenters for these observations. The Agency's estimates of employment impacts, found in the RIA for the rule, are smaller than those identified by the some commenters, though the EPA uses a different methodology that focuses on impacts specific to the electric power sector.

b. Impacts on Low-Income Consumers

Comment: Commenters expressed concern that the EPA's overview of the price increases does not consider the hardships that will be the reality of increased prices on low-income or fixed-income households or small businesses. The commenter reports increases of $ 90 million in capital costs, $ 11.4 million in annual operating costs and $ 6.4 million in annual debt service costs to achieve compliance, which will lead to a 13 percent increase in rates for the proposed rule, and a 41 percent increase for all proposed and new regulation compliance costs. The commenter argues against the EPA's view that energy efficiencies will

offset rate increases, because low income customers will need to use less electricity due to economic necessity. The commenter also sees large price increases for customers if units are converted to natural gas, which is approximately 2.5 times more expensive than the coal that the commenter currently uses to generate electricity.

Response: The EPA's estimates of increase, relative to the baseline, in the retail electricity price range from 1.3 percent to 6.3 percent regionally in 2015, with an average increase nationwide of 3.1 percent in 2015. Low-income households will thus see some increase in electricity price, but this increase should be modest. In addition, the increase in the price of natural gas as a result of this rule is expected to be 0.3 to 0.6 percent over a time horizon of 2015 to 2030. This increase in price is low enough that electricity customers should not experience a major increase in price resulting from any modest changes to electricity generated by natural gas. The roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[351]

c. State or Regional Impacts

Comment: Multiple commenters expressed concern over the impact of the rule on electricity prices and reliability in specific states or regions. These commenters were concerned that these impacts would adversely affect specific industries such as construction and manufacturing. One commenter suggested

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[351] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 to 2010, Table 8-10.

the EPA consider regional differences that will impact system reliability and costs, such as the increased impacts on regions relying heavily on coal and oil and encourages cooperation between the EPA and state and federal energy and environmental regulators.

Response: The Agency has studied possible impacts on resource adequacy as a result of this rule, and has determined that these impacts should not be significant. Furthermore, industry, along with relevant federal agencies, has the tools needed to address any reliability concerns. The Agency has prepared an updated feasibility TSD in support of the final rule, which is in the docket for this rulemaking.[352] The Agency has considered impacts on a regional basis as part of its overall analyses done using the IPM; these results are documented in the RIA for the rule and in the feasibility TSD.

The EPA's analysis shows that retail electricity price increases will not fall disproportionately on a specific region. In fact, those regions experiencing the largest change in prices are projected to have retail electricity prices below the national average both in the absence of MATS and after the implementation of MATS. In Chapter 3 of the RIA, the EPA presents retail electricity prices by region in 2015, for both the base case and MATS policy case. The six regions that are projected to have retail electricity prices above the national average price in 2015 in the absence of MATS are projected to have increases that are below the national average increase following the implementation of MATS. Those regions that have projected retail electricity price increases that are above the national

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[352] *See* "An Assessment of the Feasibility of Retrofits for the Mercury and Air Toxics Standards Rule" in the docket.

average are all projected to have retail electricity prices below the national average in the absence of MATS.

Comment: A commenter quoted National Mining Association statistics showing coal is responsible for $ 65.738 billion in annual economic activity, produces 1,798,800 jobs and $ 36.345 billion in annual labor income. The commenter reports that regions such as Appalachia, the Midwest and Rocky Mountain West will be significantly affected by the proposed rule, including increased unemployment. Other commenters stated that communities near existing coal-fired generation units will be especially hard-hit if the plants are permanently retired. The communities will suffer from job loss and diminished tax revenue.

Response: The Agency's analysis, as found in the RIA, shows that impacts to these regions are mixed. For Appalachia, coal production is projected to fall by 6 percent in 2015, while the Western coal producing region will experience a decrease of 3 percent in production in 2015. The Interior region is projected to see a 9 percent increase in production. Retail electricity prices are expected to increase by 1.3 percent to 6.3 percent in various parts of the country in 2015. Also, the estimated number of early retirements according to the Agency that may result from this rule is 4.7 GW in 2015, or less than 2 percent of all U.S. coal-fired capacity in that year. Thus, there may be some negative impacts from this rule in some regions, but these same regions will also experience some of the benefits, such as reduced premature mortality from less exposure to PM[2.5] emissions as shown in Chapter 5 of the RIA. As discussed previously, the EPA's analysis shows that retail

electricity price increases will not fall disproportionately on a specific region. In fact, those regions experiencing the largest change in prices are projected to have retail electricity prices below the national average both in the absence of MATS and after the implementation of MATS.

The results of the EPA's employment analysis, found in Chapter 6 of the RIA, indicate that the final MATS has the potential to provide significant short-term employment opportunities, primarily driven by the high demand for new pollution control equipment. While the employment gains related to the new pollution controls are likely to be tempered by some losses due to certain coal retirements, some of these workers who lose their jobs due to plant retirements could find replacement employment operating the new pollution controls at nearby units. Finally, job losses due to reduced coal demand are expected to be offset by job gains due to increased natural gas demand, resulting in a small positive net change in employment due to fuel demand changes.

While shifts in employment are difficult for those directly affected, and the Agency remains concerned about the challenges job shifts can bring to the individuals affected, Bureau of Labor Statistics data indicate that compliance with pollution control requirements is a relatively very small contributor to overall employment shifts in the U.S. economy. Specifically, the main cause of mass layoffs over the last four years according to 2007 to 2011 Bureau of Labor Statistics data is "lack of business demand," accounting for over 40 percent of the layoffs reported by industry. In contrast, all types of regulatory actions (including health, safety, and environmental) by all levels of government (Federal, State, local) combined

were cited as the primary factor in only 0.2 percent of mass layoffs over the same period.[353]

d. Retirements of Coal-Fired EGUs and Shutdowns

Comment: A commenter discussed the economic factors behind EGU retirements. These factors include the cost of alternative generation using natural gas, the cost of implementing demand response measures that can be bid into capacity markets, and the cost of continuing to generate power from an existing unit. The commenter states that regardless of the costs associated with the Toxics Rule and other EPA electric power industry regulations, some power plants were already economically unsustainable. The commenter quotes M.J. Bradley, who points out, "[o]f the 122 coal units in PJM with capacity less than or equal to *200 MW, 35* failed to recover their avoidable costs and another 52 were close to not recovering those costs. Therefore, in PJM * * * in addition to approximately 10 GW of coal generation that has or will be retired during the 7 years from 2004 to 2011, another 11 GW faces a troubling economic outlook." The commenter provides confirmation of this by the most recent PJM capacity auction, where approximately 6.9 fewer GW of coal-fired capacity cleared the auction (1.85 fewer GW were offered) as compared with the prior year's auction, and an additional 4.836 GW of new demand response (energy efficiency) resources cleared the auction. Thus, the commenter states, some claims linking retirements to the MATS are overstated and misleading. The commenter gives the example of the American Electric Power attempt to link its planned plant closures to the MATS, but those plants already

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[353] U.S. Bureau of Labor Statistics, 2011. Extended Mass Layoffs in 2010. *http://www.bls.gov/mls/mlsreport1038.pdf.*

are slated to either close or to upgrade controls to comply with existing laws. The commenter goes on to quote three independent studies that support the finding that over 50 percent of the fleet is equipped with scrubbers and the number will increase to nearly 2/3 by 2015.

Response: The EPA agrees with the findings of the independent studies mentioned by the commenter.

e. Impacts on Mining

Comment: Multiple commenters mention the proposed rule's impact on mining. One commenter mentioned increasing energy costs for the U.S. mining industry, resulting in fewer projects and associated jobs, as well as increasing dependence on foreign mineral resources. Commenters see mining impacts being disproportionally large for lignite mines, which are dependent on their co-located lignite-fired power plants. The commenters state that if the plant closes, there is no market for the lignite and the mine will also close, displacing plant workers. These impacts are largest in Texas, the largest coal consuming state and fifth largest coal producing state, as well as a deregulated electricity market. One commenter pointed out that the Texas coal market provided a buffer against natural gas price volatility and in particular believes the proposed rule does not take into account the emission reductions already achieved by industry in general and their company in particular. A commenter stated that impacts will be magnified in Texas, since it is the largest coal consuming state and mines lignite. A commenter indicated they believe it is unclear the extent to which EPA includes the impacts on the mining industry that will result from this rule.

Response: The Agency presents impacts on the coal mining sector from this rule in the RIA. Given the modest increase in coal and other energy costs associated with the rule, the Agency does not expect widespread impacts on coal mining. The Agency's modeling accounts for all emission controls and programs installed and/or implemented up through December 2010, including those in Texas.

f. Flexible Regulations

Comment: Several commenters expressed concern over the potential impacts of the regulation and believe that the requirements should be more flexible in order to mitigate these impacts.

Response: The EPA believes the requirements of the final rule have been made as flexible as possible consistent with the CAA. The final rule allows some flexibility, including allowing averaging across units in the same subcategory at a facility, allowing for an option of an input or output standard for existing units, and allowing for alternative compliance options (*e.g.*, for coal, filterable PM or total non-mercury metallic HAP or individual HAP metals). In addition, the Agency is not prescribing specific technologies as part of this final rule, but instead requiring emissions limitations be met. This approach allows the industry to find the most cost-effective approach to meeting the requirements while ensuring considerable public health benefits.

g. Temporary vs. Permanent Jobs

Comment: A commenter expressed disagreement with the EPA prediction of new jobs created, because the commenter believes far more plants will shut down

than the EPA predicts, resulting in higher job losses. The commenter also pointed out that while jobs running power plants are permanent, the jobs predicted to be created by the proposed rule are short term construction jobs, and will all occur in the same short timeframe for compliance. The commenter also stated that the EPA estimate does not include the opportunity cost of lost construction jobs due to new power plants that will not be constructed due to the proposed rules.

Response: The Agency believes that the employment impacts of the final rule will be small, as has been the case historically with regards to environmental regulation. The Agency does provide an estimate of the long-term employment impacts to the electric power sector in the RIA for the rule, and that estimate shows a range of impacts from 15,000 net jobs lost to 30,000 net jobs gained (all annual), but also recognizes important limitations to these estimates. The Agency's estimate of impacts to short-term jobs, including those in construction, accounts for both losses and gains that result from the rule. This is shown in Chapter 6 of the RIA.

Comment: Commenters believe that installation of new pollution controls would be a job-growth opportunity in their states because money spent on controls for power plants creates high-quality jobs in steel, cement and other materials, as well as in the assembling of the equipment as well as installing and operating it. A commenter shares the Alabama Fisheries Association estimate that the water-based recreation industry brings in over $ 1 billion per year to the state's economy though the state ranks third for imperiled fish with 61 bodies of water cited for Hg contamination. The commenter believes the HAP

accumulating in the waterways threatens the industry with permanent job-losses and lost revenue.

Response: The Agency agrees with the commenter that the reduction in HAP that will take place as a result of the rule over time will help to improve waterways in Alabama and thus help the water-based recreation in that state. More information on the benefits of Hg and other HAP reductions can be found in Chapter 4 of the RIA for the rule. The Agency also agrees with the commenter that the addition of control equipment for EGUs may stimulate employment in a variety of industries.

h. Natural Gas

Comment: A commenter states that natural gas use is only an option in places where infrastructure exists to supply sufficient natural gas to the EGU and other local needs and reports that year-round reliable gas delivery is rare due to requirements to meet the other needs. The commenter says that gas interruptions are prevalent in the winter, but can happen year-round, and the costs of establishing a natural gas line to a power plant can be tens of millions of dollars or more, and moving a plant to a gas source can take many years. The commenter describes the options for a Norwalk Harbor plant, and explains that the modifications are costly and difficult even before considering the modifications needed to alter the boiler and fuel supply system to allow natural gas combustion.

Response: The final rule does not prescribe either pollution control technologies to be used, nor does it dictate the types of fuels that should be burned. The requirements of the final rule are designed to allow industry to find the most cost-effective approach to

addressing harmful emissions that are covered by this action. The Agency believes that cost-effective technologies exist today and have been deployed on many power plants, and utilities will be able to find intelligent solutions to address harmful emissions. The EPA has provided supporting information as part of the preamble and RIA for this rule, along with the feasibility TSD, which demonstrate the availability and performance of technologies to meet the requirements of the final rule.

Comment: A commenter discusses the factors that could lead to higher natural gas prices not currently reflected in the EPA impact projections, including industrial load and demand not rebounding to 2008 levels and the influence of liquefied natural gas exports. The commenter asks that the EPA address a variety of factors related to its natural gas assumptions.

Response: The Agency has fully documented its assumptions and framework for modeling natural gas in IPM for both the proposed and final MATS. This information can be found in Chapter 10 of the IPM documentation (*http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter10.pdf*). The documentation provides a thorough overview of the natural gas module, describes the very detailed process-engineering model and data sources used to characterize North American conventional, unconventional, and frontier natural gas resources and reserves and to derive all the cost components incurred in bringing natural gas from the ground to the pipeline. Also documented are the resource constraints, liquefied natural gas (LNG), demand side issues, the natural gas pipeline network and capacity, procedures used to capture pipeline transportation costs, natural

gas storage, oil and natural gas liquids (NGL) assumptions, and key gas market parameters.

i. Compliance Timeline and General Timeline

Comment: A commenter states that the proposed rule will require costs be passed on to consumers, meaning state public utility commissions will be flooded with requests for rate increases from utilities trying to recover expenditures. The short deadline will also result in a large number of extension requests made to state permitting authorities, further burdening them.

Response: The compliance date for this rule for existing sources will be 3 years and 60 days after publication of the final rule in the **Federal Register**, or approximately March 2015. Thus, there will be some time before the impacts of this rule such as any increase in retail electricity prices become a concern. It also should be noted that increases in retail electricity prices will be 3.1 percent on average in 2015, with a range regionally from 1.3 percent to 6.3 percent.

Comment: A commenter reports that they will need to install add-on pollution controls to meet the proposed emission standards as well as implement other physical or operational changes. The commenter expresses concern about the number of pre-construction steps that would be required, as well as the new construction activities and the challenges of scheduling sequence relative to interconnections and other tie-in considerations involved in compliance.

Response: The Agency has addressed concerns with the feasibility and timing of control installations in its report on the subject (*See* feasibility TSD contained in the docket for this rule).

Comment: Multiple commenters do not believe that labor availability will constrain control installation in the required timeframe and cites an Institute of Clean Air Companies (ICAC) response that it will not for these reasons:

1. The power sector has demonstrated ability to install large number of systems in short time period;

2. The majority of coal plans have installed control systems already;

3. Fewer resource and labor-intensive control options being used for compliance; and

4. End users have utilized cost reducing and implementation efficiency strategies for efficient deployment of technologies.

Another commenter states that a wide range of technical and economically feasible practices and technologies are available currently to meet the emission limits and are in use around the country.

Response: These comments are generally consistent with the conclusions of the Agency's analyses on feasibility of control installations for this rule as found in the feasibility TSD in the docket for this rulemaking.

j. Burden Outweighs Environmental Gain

Comment: Several commenters state that the EPA has no data relating to benefits from reducing non-mercury HAP, so the costs of the proposed rule exceed the HAP benefits by 29,000 times. One commenter states that the impact analysis was largely focused on Hg with little support for other HAP reductions and failed to provide account of true costs and benefits.

Response: While we are not able to monetize the benefits from reductions of non-mercury HAP that will

take place, these important effects are discussed qualitatively in Chapter 4 of the RIA. The quantified benefits of this rule include the reductions in non-HAP emissions such as SO_2 and $PM_{2.5}$ that will occur as a co-benefit of this rule as modeled by EPA. The total benefits are estimated to outweigh the total annual costs of the rule by a margin of either 3 to 1 or 9 to 1, depending on the benefits estimate and discount rate used. These reductions are credible and are considerable in size. The estimates of these benefits reflect the latest scientific understanding on the subject. More information on the estimates and the methodology for their preparation can be found in the RIA for the rule.

Comment: Several commenters consider the proposed rule to be the most expensive clean air rule ever. They point out the estimated $ 10.9 billion annual cost in 2015 and approximate 1,200 existing coal-fired EGUs affected, both of which were estimated by the EPA. Commenters believe the EPA's estimates are incorrect and the true cost will be far more, due to cumulative effects of all proposed power sector rules, and indirect costs from job losses, reduced productivity and competitiveness resulting from electricity costs. They ask the EPA to keep these high costs in mind when evaluating impacts of the proposed rule and consider the costs with respect to the benefits. One commenter requests that the EPA explain how its approach utilized "the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible" and includes analyses by EIA, EEI, NERC, NERA, Credit Suisse, ICF, and Burns & McDonnell.

Response: As noted earlier, the Agency did not prepare a cumulative impact analysis to accompany the rule for the following reasons: (1) The various EO

requirements that the Agency must comply with require us to estimate impacts specific to this rule; (2) decisionmakers and the public need to know the impacts specific to a particular rule in order to judge the merits of the regulation; and (3) estimates specific to a particular rule are more transparent than those from a cumulative impact analysis. A cumulative impact analysis lumps several regulations together and can potentially mask a high-cost/low benefit regulation among other rules that may have large net benefits. By analyzing each regulation separately, EPA makes clear statements about the impacts, costs, and benefits that are estimated as a result of this particular regulation.

This does not, however, mean EPA has failed to incorporate these regulations into this analysis. The inclusion of CSAPR and other regulatory actions (including federal, state, and local actions) in the IPM base case reflects the level of controls that are likely to be in place in response to other requirements apart from MATS. This base case provides meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions, while isolating the incremental impacts of MATS. These results are presented in Chapter 3 of the RIA.

Additionally, the Agency does reflect on the cumulative impacts of our regulations. In March 2011, EPA issued the Second Clean Air Act Prospective Report which assessed the benefits and costs of regulations pursuant to the 1990 Clean Air Act Amendments. The study examines the cumulative impact of these regulations (found at *http://www.epa.gov/air/sect812/feb11/summaryreport.pdf*). As shown in the report, the direct benefits from the 1990 Clean Air Act Amendments are estimated to reach almost $

2 trillion for the year 2020, a figure that dwarfs the direct costs of implementation ($ 65 billion). The full report is at *http://www.epa.gov/air/sect812/prospective2.html.*

The direct benefits of the 1990 Clean Air Act Amendments and associated programs are estimated to significantly exceed their direct costs, which means economic welfare and quality of life for Americans were improved by passage of the 1990 Amendments. The wide margin by which benefits are estimated to exceed costs, combined with extensive uncertainty analysis, suggest it is very unlikely this result would be reversed using any reasonable alternative assumptions or methods. The analysis presented in the RIA for the current regulation uses a similar methodology.

The techniques employed by the Agency for generating benefits and costs, and consider the most recent and complete data available to the Agency. The EPA recognizes that the analyses have caveats and limitations, and we discuss our analyses and their caveats and limitations in the RIA for the rule, as well as in the benefits section of the preamble. The Agency has also revised the cost analyses for the final rule to reflect data received in public comments on the proposed rule, and costs are lower than when the rule was proposed.

k. Impact on State Regulators

Comment: Several commenters expressed concern over the burden imposed on state regulatory agencies by the rule.

Response: The Agency has estimated the costs of implementation of the rule to states that own EGUs affected by the rule, and has included this analysis in

the RIA. The Agency has updated this analysis for the final rule and it is included in the RIA. While the EPA has not prepared an analysis of the impacts of the rule on state programs, the Agency does not believe the rule will be unduly burdensome to the state regulatory agencies. The EPA works closely with state regulatory authorities to ensure that the rules are implemented properly, and the Agency will continue to do so in support of this final rule.

Comment: A commenter states that the reductions in SO_2 and $PM_{2.5}$ required by the proposed rule will assist state and local air pollution control agencies to meet health-based air quality standards, reduce haze and improve visibility. The commenter points out that substantial reduction in emissions made by the very large sources under the proposed rule will lead to fewer pollution controls needed at smaller sources to meet health-based ambient air requirements. This is a far more cost-effective approach than controls at smaller facilities and is the lowest cost path to improved public health and a cleaner environment.

Response: The EPA acknowledges that the HAP standards in this final rule will lead to considerable co-benefit reductions in PM and SO_2.

l. Miscellaneous

Comment: A few commenters discussed the impact of the rule on the federal budget deficit. One commenter points out that the proposed rule will affect the federal budget in two ways:

1. Direct compliance costs to electric generating units (EGUs) owned by federal agencies; and

2. Pass-through compliance costs paid in the form of higher prices for electricity purchased by federal agencies.

Response: The Agency estimates the direct compliance costs to EGUs that are federally owned as part of the overall cost analysis completed for the proposal and disclosed in the RIA for the rule. The Agency does not provide an estimate of the impact on federal agencies from higher electricity prices associated with the rule, however. This type of analysis is not required under EO 12866 and statutory requirements.

H. Testing and Monitoring

Comment: Commenters raised numerous issues with the testing and monitoring requirements for initial and continuous compliance. The following discussion highlights the comments and responses to a number of the critical issues and describe where the comments have resulted in a significant rule change or where we disagreed with commenters' suggestions of issues or need for changes in the rule. Additional comments and responses are addressed in the Response to Comments document included in the docket for the final rule.

Test Methods. A number of commenters suggested that we should allow for the use of Method 5B to determine compliance with the PM emission limit. In addition, a number of commenters objected to the frequency of stack testing when used as the method for demonstrating continuous compliance. Commenters also objected to the requirement for testing one pollutant when the source was complying with an optional surrogate (or vice versa); for example, commenters objected to testing for HCl if a unit was complying with the optional SO[2] limit, or testing for

metals if the unit was complying with the optional PM limit.

Response: Although Method 5B is specified for wet scrubber-controlled utility boilers under 40 CFR part 60, subparts D, Da and Db, we are excluding Method 5B for demonstrating compliance with the filterable PM emissions standard in this final rule. The extended high temperature heating of the filters prior to weighing as specified in Method 5B would introduce differences between the compliance test data and the data that underlie the filterable particulate standard. Because the test data that underlie and filterable particulate standard are based primarily on Method 29 and Method 5 data collected at 320 [degrees] F or comparable filterable particulate methods, we are specifying those same methods for determining compliance with the standard.

For stack test frequency, we modified the final rule to require quarterly testing to demonstrate continuous compliance. In addition, we agree that testing should be required only for the emission limits that your source is complying with, and, thus, the final rule does not require testing of both the pollutant and the surrogate.

Comment: Fuel Analysis Methods. A number of commenters raised various concerns with the fuel analysis methods specified in the proposed rule.

Response: Based on the comments received and a further review of the technical challenges associated with the proposed fuel analysis requirements, we have not finalized the proposed fuel analysis requirements. As the rule no longer requires operating limits based on fuel content or fuel analysis, the comments on this issue are largely moot. For LEEs, we agree that the

proposed LEE ongoing eligibility requirements were overly burdensome and restrictive. As a result, existing solid or liquid fired units that qualify for Hg LEE status will be required to conduct a 30-day test for Hg using Method 30B each year. Neither fuel analysis nor adherence to an operating limit will be required. Should an annual test show ineligibility for LEE status, the source will revert to the requirements for Hg monitoring using CEMS or sorbent traps or, for oil-fired units, quarterly emissions testing. Existing solid or liquid fired units that qualify for non-mercury LEE status will be required to conduct a stack test every 3 years, and neither fuel analysis nor adherence to an operating limit will be required. Should the stack test show ineligibility for LEE status, the source will revert to using CEMS or PM CPMS or conducting quarterly emissions testing.

Comment: Operating Parameter Limits: Some commenters objected to the use of enforceable operating parameter limits, requested that the rule be more consistent with the compliance assurance monitoring program, and raised specific objections to certain parameters required for certain control devices. Commenters also raised concerns about a PM CEMS operating limit establishing a de facto more stringent PM emission limit than the one being tested for under the total PM standard in the proposal.

Response: We believe that continuous monitoring in the form of CEMS, sorbent trap monitoring systems, and PM CPMS, or frequent stack emissions testing are appropriate to ensure ongoing compliance with this final rule. We also agree with commenters that some of the monitoring provisions in the proposal may have been duplicative and unnecessary. In order to provide flexibility in the final rule, we have retained a source's

ability to define an operating limit and to monitor using a PM CPMS as an option to periodic filterable PM emissions testing.

The final rule establishes the PM CPMS as an operating limit monitor and not a direct filterable PM emission monitoring requirement that meets PS 11 requirements. Although we recognize the importance of continued control device performance to ensure emissions minimization, we also are aware that other rules that apply to these units including, but not limited to, the Operating Permits rule, the Compliance Assurance Monitoring rule, the ARP rules, and the NSPS already require continuous monitoring in most cases. Those rules will remain in effect so the need to impose additional operating limits monitoring or CEMS on those units is much reduced.

The final rule also provides for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach. In that case, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of satisfying the requirements in Performance Specification 11 in Appendix B to 40 CFR part 60 and Procedure 2 in Appendix F to part 60. The EPA provided this option in response to the comments in order to provide a straightforward direct measure of compliance that some sources may want to implement.

Comment: Hg CEMS. Commenters raised a number of technical concerns about Hg CEMS. Many commenters requested modifications so that the requirements would be more consistent with 40 CFR part 75 monitoring requirements. Some commenters questioned the ability of the technology to demonstrate compliance with emission limits at very low

levels especially for new sources. Commenters also opposed high data availability requirements given that the technology is new and difficult to operate and maintain.

Response: We indicated in the proposed rule the intent to adopt CAMR-based requirements for Hg monitoring in place of the general 40 CFR part 63 performance specifications and QA requirements. With CAMR, these operating and reporting requirements for Hg CEMS went through notice and comment rulemaking for the same sources as covered by this final rule. Although CAMR was set aside on other grounds, these technical specifications and QA requirements reflect significant input from stakeholders and analysis by the EPA to establish an appropriate foundation for Hg monitoring at electric utilities under the CAA. For the final rule, we have made conforming changes to ensure that this intent is carried out effectively throughout the rule text and Appendix A, as well as including certain additional clarifications based on the input received in response to the proposed rule. We have also removed a cycle time test as unworkable for certain types of Hg CEMS.

The final rule provides the option for use of either Hg CEMS or sorbent trap monitoring systems. We believe the record clearly shows these to be proven technologies each providing certain advantages. For existing and some of the new unit standards, the level of the NIST-traceable Hg gas standards will be adequate and consistent with existing applications of Hg CEMS. For the lowest limits and other applications where an integrated sampling system offers advantages, affected facilities may opt to use sorbent trap monitoring systems to comply. There are data in the recent draft report entitled "Determining the

Variability Of CMMS At Low Hg Levels,"[354] that demonstrate reasonable performance of at least one Hg CEMS at Hg levels below 1.0 microgram per cubic meter ([mu]g/m<3>) down to approximately 0.1 [mu]g/m<3>. Finally, there is no specific minimum data availability requirement for Hg CEMS (or any other CMS required under this final rule). This issue is discussed further below.

Comment: SO_2 CEMS: Although commenters were generally supportive of the ability to use SO_2 CEMS for units with FGD installed to demonstrate compliance with an alternate SO_2 emission limit instead of the HCl emission limit, there were some concerns with aspects of the proposal. Commenters requested that the SO_2 monitoring requirements rely on 40 CFR part 75 given that their sources were already meeting those requirements and that this rule not establish any new requirements, especially a fourth linearity level and the application of 7-day calibration error tests for units with low concentrations (where 40 CFR part 75 provides an exemption). Commenters were also concerned that the rule language only allows the option where the FGD is operated "at all times" which seems to imply that the option is not allowed if the source ever bypasses the FGD for start-up, shutdown, or malfunction reasons.

Response: After reviewing the comments and assessing the need for an additional calibration gas at the emissions limit, we have removed this requirement from the final rule while retaining the requirement for a linearity check even for SO_2 monitors with low span values (</= 30 ppm). A source can already report linearity tests for these units

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[354] *http://www.icci.org/reports/10Laudal6A-1.pdf.*

within the context of the existing ECMPS reporting without triggering any critical errors. This test can be accommodated within the current framework without causing issues for 40 CFR part 75 reporting. The requirement for a 7-day calibration error test is removed. For the "at all times" language, we have clarified this in the final rule. The intent is that the FGD be operated during all routine boiler operations, and not operated intermittently, seasonally, or on some other non-fulltime basis.

Comment: HCl CEMS. In general, commenters argued that HCl CEMS do not have an approved performance specification and are not widely demonstrated as a proven technology. Those concerns were also mentioned for HF CEMS.

Response: We disagree with commenters' contention that continuous HCl monitoring is premature or not available for the measurement at the emission limits set in the final rule. HCl CEMS are being used on source categories such as municipal waste combustors and EGUs. We have reviewed HCl CEMS vendor technology claims and found sufficient capability to support this rule requirement. We are engaged with representative stakeholders to develop a generic performance specification for HCl CEMS scheduled for completion in time to be responsive to compliance with this rule.

The final rule provides several options for HCl and/or HF monitoring including:

(1) Using Fourier Transform Infrared (FTIR)-based HCl CEMS and/or HF CEMS complying with Appendix B to the rule which relies on PS 15,

(2) Seeking approval for an alternative HCl monitoring procedure through *40 CFR 63.7(f)*,

(3) Monitoring compliance continuously with the alternate SO_2 emission limit at coal-fired or other solid fuel affected facilities equipped with FGD technology for SO_2, and

(4) Quarterly reference method testing.

Including these options in the final rule provides flexibility to adopt CEMS monitoring options as the technology continues to mature and the new, non-technology-specific EPA performance specifications becomes available.

Comment: Bypass Stacks. Several commenters raised concerns about the technical feasibility of monitoring bypass stacks with a CEMS.

Response: We have modified the bypass stack monitoring requirements. Under 40 CFR part 75, we allow the use of a maximum potential concentration value for reporting when emissions are vented to a bypass stack. That approach works within the context of an emissions trading program, but is not appropriate when evaluating compliance with a specific emission limit. Thus, we have provided two other options. One is to monitor the bypass stack, consistent with the final rule. The other is to treat any hours of bypass stack emissions as periods of monitor downtime and hours of deviation from the monitoring requirements. Note that a source's units must continue to meet their 30-boiler operating day emissions limits during malfunction periods.

Comment: 40 CFR part 75 Issues. There were a number of general comments about the value of relying on 40 CFR part 75 requirements, including elements such as conditional data validation. The commenters generally agreed that the 40 CFR part 75 bias test and bias adjustment factor, and the 40 CFR

part 75 substitute data provisions should not apply. Instead of substitute data, many commenters suggested that we needed to clarify the valid reasons for monitor downtime and establish an appropriate minimum data availability requirement.

Response: We have attempted to harmonize the CEMS requirements in this final rule with those under 40 CFR part 75 wherever appropriate. One of those examples is the inclusion of conditional data validation for Hg CEMS. We disagree that this final rule needs a minimum data availability requirement. We have not included any specific minimum data availability requirement for CEMS or other monitoring in this final rule nor do we provide a specific tool for data substitution. We believe that there are other provisions in the final rule to provide incentives to conduct monitoring in a manner consistent with good air pollution control practices and to provide data sufficient to demonstrate compliance with a relatively long-term (30-boiler operating day) emissions rate limit. We agree that data quality certainty associated with any calculated value decreases with the collection of less data such as would occur with extended periods of monitoring system downtime. Even so, we believe also that it is necessary and critical for compliance with the regulation that a source use all measured data collected during an averaging period to assess compliance regardless of any periods of missing data. Sources should not disqualify any data otherwise meeting required data quality requirements simply because there were data missing for other hours or days of the averaging period.

Instead of a minimum data availability threshold that would invalidate data collected for some

averaging periods because one did not collect data for at least a specified percent of an averaging time, the final rule requires that a source report as deviations to the rule failure to collect data during required periods if these deviations are not covered by exceptions allowed in the final rule.

On the issue of applying a data substitution procedure to represent actual emissions or pollution control performance, we are not requiring data substitutions under this rule. We believe, however, that defensibility concerns make it incumbent on the source to collect and evaluate other information in accordance with *40 CFR section 63.6(f)(3)* during periods of monitoring downtime to assure compliance with the applicable emissions limitations and standards.

We believe that enforcement authorities also can and should determine whether a source is meeting any monitoring system operating requirements. Should the source or the enforcement authority be concerned about the representativeness of data such as during periods of missing data, either one may consider collecting information through other means (*e.g.*, supplemental emissions testing) to fill data gaps not only because such gaps are deviations from the rule but such gaps can lead to uncertainty about compliance status.

We further believe that the final rule provides sufficient means to ensure CMS performance and ongoing compliance without specifying an arbitrary numerical minimum data availability or data substitution requirement. We believe that specifying failure to collect required or otherwise excepted data as a deviation from the rule will provide the necessary

incentive to collect data sufficient to demonstrate compliance with the limits in the final rule.

Comment: Recordkeeping. Several commenters opposed the requirements related to maintaining records on site and for 5 years.

Response: We believe the recordkeeping and retention requirements are consistent with other requirements already in place, specifically *40 CFR 63.10 (b).*

In addition, the 5-year retention period is the general rule for all recordkeeping for all sources under the part 70 operating permits program. Given that the General Provisions for 40 CFR part 63 and part 70 already establish a 5-year retention period, we believe it is justified in using those precedents for the retention periods under this subpart. If we stayed silent on retention period in this subpart, the General Provisions would provide for the 5-year retention as would the part 70 requirements. Thus, this action does not establish any new retention requirements, but merely confirms that the existing retention requirements apply.

Comment: Electronic Reporting. In the proposed rule, we requested comment on using ECMPS for reporting under this rule, as well as other options including the ERT. Commenters generally supported the use of ECMPS, especially for CEMS data. Some commenters requested an additional rulemaking on the specific data elements to be collected. There were some concerns raised about the ERT given experience during the 2010 ICR process during the development of this rule.

Response: We recognize that emissions reporting for continuously measured pollutants (SO_2, NO_x, etc.) and for periodically measured pollutants (PM, HAP

metals, etc.) have different data demands. We recognize that minor revisions of the ECMPS will fulfill our data needs for most continuously measured pollutants and we will make these modifications for receipt of the additional CEMS data. We also recognize the need for substantial modifications to the ECMPS to accommodate the data needs for periodically measured pollutants and certain CEMS data such as PM CEMS data and possibly HAP metals CEMS data. Although major modifications of the ECMPS would be required for periodic compliance tests by isokinetic and instrumental test methods (as well as certain types of CEMS), only minor revisions are required of the ERT to receive these tests. We are implementing the changes in the ERT that are required to provide the software tools to implement the delivery of these performance test data to us.

The electronic submission of compliance test reports to us through the Central Data Exchange (CDX) is not solely for the purpose of developing improved emissions factors as some commenters assert. Although populating WebFIRE will allow us to improve emissions factors, we intend to use data stored in WebFIRE as the primary location for compliance test reports for use by regulatory authorities. The electronic submission of compliance test reports is a continuation of our efforts to bring the submission and sharing of environmental data into the modern age. The storage of this compliance data in our WebFIRE provides a convenient location which is already used to store source test data.

As federal and state and local agencies' data systems mature, information provided through the ERT will be used to populate these data systems. We are currently upgrading the AIRS Facility System and expect to

replace manually entered information with electronic population from the ERT. We are also working with several state and local agencies to adopt the use of the ERT for delivery of compliance test reports. The ERT is also much improved since the version used during the 2010 ICR process, and there is no expectation that the information to be reported under this final rule will be as extensive as some of the data reported for the 2010 ICR purposes.

We disagree that a separate and independent regulatory action is required to implement electronic reporting for selected regulated sources. Each of these regulatory actions for selected source categories provides ample notice and the opportunity for individuals to provide comment. We also disagree that the system to receive the compliance data must be operational prior to establishing the requirement for regulated sources to submit compliance data electronically. We are on track to have the capability to receive electronic compliance tests through our CDX in sufficient time to receive all utility source test reports required by this final rule.

We do plan a separate and independent regulatory action to implement electronic reporting for regulated entities which are covered by past and future rules. Although we have provided draft procedures for the development of emissions factors, that effort is an ancillary effort to the electronic delivery of compliance test reports. It is our intention to convert to the electronic delivery and storage of all air emissions compliance source test data. With this transition, we believe this valuable information will be more readily available not only for compliance purposes but also for a variety of other uses.

I. Emissions Averaging

Comment: In response to our request for comments on the suitability of emissions averaging and need for a discount factor, we received a range of suggestions, including requests for clarification regarding eligibility, points for and against the need for a discount factor, and suggestions to ease implementation.

Response: We are finalizing that owners and operators of existing affected sources may demonstrate compliance by emissions averaging for EGUs at the affected source that are within a single subcategory and that rely on emissions testing as the compliance demonstration method. See section VI of thie preamble for a fuller discussion.

J. LEE Criteria

Comment: A commenter supported the LEE provisions but believed one of the LEE eligibility criteria should set at 29.0 lb/year, rather than 22.0 lb/year. The commenter suggested 29.0 lb/year to be an equally reasonable cut point, especially since that value matches the low mass emitter Hg monitoring cutoff in CAMR and the low mass emitter Hg monitoring cutoff that several states have adopted, including Illinois, 35 Ill. Admin. Code section 225.240(a)(4). (*See, e.g.*, Colorado (5 Colo. Code Regs. section 1 00 1-8, Reg. No.6, part B, Section VIII.B.10); Michigan (Mich. Admin. Code R. 336.2160); Montana (Mont. Admin. R. 17.8771(12))). Further, a LEE cutoff of 29.0 lb would eliminate conflicts and confusion with low mass emitter provisions in existing state Hg programs and significantly reduce compliance costs and burdens for the additional qualifying units without adversely affecting compliance assurance with the EGU NESHAP Hg emission limits or materially increasing the number of potential qualifying LEEs. Given the many other

costly burdens that the rule would impose, the benefit of LEE to a qualifying unit is not insignificant.

Response: The Agency reviewed the commenter's suggestions, and one of the LEE eligibility criteria in the rule has been revised from 22.0 to 29.0 lb of Hg per year. The Agency finds the result of consistency with existing state regulations outweighs the two percent difference in nationwide Hg mass emissions, from 5 percent to 7 percent, for LEE eligibility.

VIII. Background Information on the NSPS

A. What is the statutory authority for this final NSPS?

New source performance standards implement CAA section 111(b), and are issued for categories of sources which cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. Section 111 of the CAA requires that NSPS reflect the application of the best system of emissions reductions which (taking into consideration the cost of achieving such emissions reductions, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. The level of control prescribed by CAA section 111 historically has been referred to as "Best Demonstrated Technology" or BDT. In order to better reflect that CAA section 111 was amended in 1990 to clarify that "best systems" may or may not be "technology," the EPA is now using the term "best system of emission reduction" or BSER. As was done previously in analyzing BDT, the EPA uses available information and considers the emission reductions and incremental costs for different systems available at reasonable cost. Then, the EPA determines the

appropriate emission limits representative of BSER. Section 111(b)(1)(B) of the CAA requires EPA to periodically review and revise the standards of performance, as necessary, to reflect improvements in methods for reducing emissions.

B. What is the regulatory authority for the final rule?

The current standards for steam generating units are contained in the NSPS for EGUs (40 CFR part 60, subpart Da), industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db), and small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc).

The NSPS for EGUs (40 CFR part 60, subpart Da) were originally promulgated on June 11, 1979 *(44 FR 33580)* and apply to units capable of firing more than 73 megawatts (MW) (250 MMBtu/h) heat input of fossil fuel that commenced construction, reconstruction, or modification after September 18, 1978. The NSPS for EGUs also apply to industrial-commercial-institutional cogeneration units that sell more than 25 MW and more than one-third of their potential output capacity to any utility power distribution system. The most recent significant amendments to emission standards under 40 CFR part 60, subpart Da, were promulgated in 2006 *(71 FR 9866)* resulting in new PM, SO_2, and NOP_2 limitations for 40 CFR part 60, subpart Da units.

The NSPS for industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db) apply to units for which construction, modification, or reconstruction commenced after June 19, 1984, that have a heat input capacity greater than 29 MW (100 MMBtu/h). Those standards were originally promulgated on November 25, 1986 *(51 FR 42768)* and also

have been amended since the original promulgation to reflect changes in BSER for these sources.

The NSPS for small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc) were originally promulgated on September 12, 1990 *(55 FR 37674)* and apply to units with a maximum heat input capacity greater than or equal to 2.9 MW (10 MMBtu/h) but less than 29 MW (100 MMBtu/h). Those standards apply to units that commenced construction, reconstruction, or modification after June 9, 1989.

IX. Summary of the Final NSPS

The final rule amends the emission standards for SO_2, NOP_2, and PM in 40 CFR part 60, subpart Da. Only those units that begin construction, modification, or reconstruction after May 3, 2011, will be affected by the final rule. Compliance with the emission limits of the final rule will be determined using testing, monitoring, and other compliance provisions similar to those set forth in the existing standards. In addition to the emissions limits contained in the final rule, we also are including several technical clarifications and corrections to existing provisions of the subparts.

A. What are the requirements for new EGUs (40 CFR part 60, subpart Da)?

The filterable PM emissions standard for new and reconstructed EGUs is 11 nanograms per joule (ng/J) (0.090 pound per megawatt hour (lb/MWh)) gross energy output regardless of the type of fuel burned. The PM emissions standard for modified EGUs is essentially equivalent to the existing requirements of 13 ng/J (0.015 lb/MWh) heat input regardless of the type of fuel burned. Compliance with this emission

limit can be determined using testing, monitoring, and other compliance provisions similar to those for PM standards set forth in the existing rule. While not required, PM CEMS may be used as an alternative method to demonstrate continuous compliance and as an alternative to opacity and parameter monitoring requirements.

The SO_2 emission limit for new and reconstructed EGUs is 130 ng/J (1.0 lb/MWh) gross energy output or 97 percent reduction regardless of the type of fuel burned with one exception. The EPA neither proposed to amended the SO_2 standard for coal refuse-fired EGUs, not reopened the issue of whether coal refuse-fired EGUs is an appropriate subcategory, and, therefore, that emissions standard is unchanged. The SO_2 emission limit for modified EGUs burning any fuel is 180 ng/J (1.4 lb/MWh) gross energy output or 90 percent reduction. Compliance with the SO_2emission limit is determined on a 30-boiler operating day rolling average basis using a CEMS to measure SO_2 emissions and following the compliance provisions in the proposed rule.

The NO_x emission limit for new and reconstructed EGUs is 88 ng/J (0.70 lb/MWh) gross energy output regardless of the type of fuel burned with one exception. The exception is that for new and reconstructed EGUs that burn over 75 percent coal refuse (by heat input), the NO[X] emission limit is 110 ng/J (0.85 lb/MWh) gross energy output. The NO_x limit for modified EGUs is 140 ng/J (1.1 lb/MWh) gross energy output regardless of the type of fuel burned in the unit. Compliance with this emission limit is determined on a 30-boiler operating day rolling average basis using testing, monitoring, and other compliance provisions similar to those in the proposed rule.

As an alternative to the NO_x standard, owners/operators of new and reconstructed EGUs may elect to comply with a combined NO[X] /CO standard of 140 ng/J (1.1 lb/MWh) with one exception. The exception is that for new and reconstructed EGUs that burn over 75 percent coal refuse (by heat input) on an annual basis, the NO_x /CO emission limit is 160 ng/J (1.3 lb/MWh) gross energy output. Finally, owners/operators of modified EGUs may elect to comply with a combined NO_x /CO standard of 190 ng/J (1.5 lb/MWh).

B. Additional Amendments

See the Response to Comments document.

X. Summary of Significant Changes Since Proposal

A. Emission Limits

The proposal included a combined (filterable plus condensable) PM standard. The final standard is based only on filterable PM. No standard is being established for condensable PM. The rationale for this is set forth in the Response to Comments (RTC) document for this final rule (the NSPS Final Rule RTC).

The proposal requested comment on whether the final standard should include a stand-alone NO[X] standard or a combined NO_x /CO standard. In response to comments we received and our own further evaluation of the situation, the final standard includes a stand-alone NO_x standard and an optional, but not required, combined NO_x /CO standard as an alternative to the amended NO_x standard. Again, our full rationale for this is set forth in the NSPS Final Rule RTC. The proposal also included a request for

comment on whether the standard should be based on gross or net output. In response to comments we received and our own further evaluation of the situation, the final standards are based on an amended definition of gross output with an optional net output-based standard. This too is addressed more fully in the NSPS Final Rule RTC.

The proposal included alternate emission standards for commercial demonstration projects. Proposed commercial demonstrations included pressurized fluidized beds, multi-pollutant control technologies, and advanced combustion controls. The final rule includes the commercial demonstration permit exemption for pressurized fluidized beds and multi-pollutant control technologies, but not advanced combustion controls. Advanced combustion controls are applicable to existing facilities and the exemption is not necessary to further the development of the technology.

B. Requirements During Startup, Shutdown, and Malfunction

For startup and shutdown, the requirements for PM have changed since proposal. For periods of startup and shutdown, the EPA is finalizing work practice standards for PM in lieu of numeric emission limits. Emissions incurred during periods of startup and shutdown for PM are not used in demonstrations of compliance with the 30-boiler operating day rolling average period applicable for numeric emission standards.

XI. Public Comments and Responses to the Proposed NSPS

See the Response to Comments document.

XII. Impacts of the Final Rule

The EPA anticipates significant public health and environmental benefits from the rule as a direct result of the substantial reduction in the emissions of several pollutants, including SO_2, Hg, acid gases and fine particles and metals. For example, exposure to Hg can damage the developing nervous system, which can impair children's ability to think and learn, and fine particles can cause adverse cardiovascular effects. Further, reducing Hg deposition to ecosystems will benefit wildlife including fish, birds, and mammals. Fish and fish-eating birds, such as the common loon, and mammals suffer reproductive, survival, and behavioral impairments due to mercury exposure. These effects have also been observed in insect-eating and wading birds, including egrets and white ibis. Reductions of emissions targeted by this rule also will slow acidification and eutrophication of water bodies.

Additionally, the EPA anticipates significant non-health, non-ecological benefits from this rule. The fine particle and SO_2 emission reductions achieved by this rule will improve visibility, which is especially important for our national parks. Emissions reductions from this rule will also avoid an estimated $ 360 million (in $ 2007) of climate-related costs, such as agricultural productivity and property damage from increased flood risks.

A. What are the air impacts?

The EPA anticipates significant emission reductions under the final rule from coal-fired EGUs, which are of particular interest due to their share of total power sector emissions. In 2015, annual HCl emissions are projected to be reduced by 88 percent, Hg emissions reduced by 75 percent, and $PM_{2.5}$ emissions reduced by

19 percent from coal-fired EGUs greater than 25 MW. In addition, the EPA projects SO_2 emission reductions of 41 percent, and annual CO_2 reductions of 1 percent from coal-fired EGUs greater than 25 MW by 2015, relative to the base case. *See* Table 7.

Table 7--Summary of Emission Reductions From Coal-Fired EGUS Greater Than 25 MW (TPY)

	SO[2] (million tons)	NO[X] (million tons)	Mercury (tons)	HCl (thousand tons)	PM[2.5] (thousand tons)	CO[2] (million metric tonnes)
Base Case	3.3	1.7	27	45	270	1,906
MATS	1.9	1.7	7	6	218	1,882
Change	-1.4	0.0	-20	-40	-52	-23

Note: Numbers may not add due to rounding.

The reductions in this table do not account for reductions in other HAP which will occur as a result of this rule. For instance, the fine particulate reductions presented above only partly reflect reductions in many heavy metal particulates, and the HCl reductions above only partly reflect reductions of all acid gases. This rule will also result in additional HAP reductions from oil-fired EGUs, which are covered by the rule but are not included in the EPA's analysis of emission reductions.

B. What are the energy impacts?

The EPA projects that approximately 4.7 GW of coal-fired generation (less than 2 percent of all coal-fired capacity and 0.5 percent of total generation capacity in 2015) may be uneconomic to maintain and

may be removed from operation by 2015. These units are predominantly smaller, less frequently used, and are dispersed throughout the country. If current forecasts of either natural gas prices or electricity demand were revised in the future to be higher, that would create a greater incentive to make further investments in these facilities and keep these units operational.

The final rule has other important energy market implications. Average nationwide retail electricity prices are projected to increase in the contiguous U.S. by 3.1 percent in 2015. The average delivered coal price is projected to increase by less than 2 percent in 2015 as a result of shifts within and across coal types. The EPA also projects that electric power sector-delivered natural gas prices will increase by between 0.3 and 0.6 percent over the 2015 to 2030 timeframe, on average, and that natural gas use for electricity generation will increase by less than 200 billion cubic feet (BCF) in 2015. These impacts are well within the range of price variability that is regularly experienced in natural gas markets. Finally, the EPA projects coal production for use by the power sector, a large component of total coal production, will decrease by 10 million tons in 2015 from base case levels, which is about 1 percent of total coal produced for the electric power sector in that year.

C. What are the cost impacts?

The power industry's "compliance costs" are represented in this analysis as the change in electric power generation costs between the base case and policy case in which the sector pursues pollution control approaches to meet the MATS emission standards. In simple terms, these costs are the resource costs of

direct power industry expenditures to comply with the EPA's requirements.

The EPA projects that the annual incremental compliance cost of MATS is $ 9.6 billion in 2015 ($ 2007). The annualized incremental cost is the projected additional cost of complying with the rule in the year analyzed, and includes the amortized cost of capital investment and the ongoing costs of operating additional pollution controls, needed new capacity, shifts between or amongst various fuels, and other actions associated with compliance.

The total incremental compliance cost includes compliance costs modeled in IPM of $ 9.4 billion, costs modeled outside of IPM for oil-fired EGUs of $ 56 million, and monitoring, reporting, and recordkeeping costs of $ 158 million.

D. What are the economic impacts?

For this final rule, EPA analyzed the costs using the IPM. The IPM is a dynamic linear programming model that can be used to examine the economic impacts of air pollution control policies for a variety of HAP and other pollutants throughout the contiguous U.S. for the entire power system.

Documentation for IPM can be found in the docket for this rulemaking or at *http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.*

The EPA performed a screening analysis for impacts on small entities by comparing compliance costs to sales/revenues (*e.g.*, sales and revenue tests). The EPA's analysis can be found in Chapter 7 of the RIA for this rule. The EPA has also prepared a Final Regulatory Flexibility Analysis (FRFA) that discusses

alternative regulatory or policy options that minimize the rule's small entity impacts.

Although a stand-alone analysis of employment impacts is not included in a standard cost-benefit analysis, the current economic climate has led to heightened concerns about potential job impacts. Executive Order 13563 specifically states that our "regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and *job creation* " (emphasis added).

Under conditions of full employment, it is conventional to assume that regulations will merely shift jobs from one sector to another, without having a material effect on employment levels. Potential employment effects are of greater concern in the current economic climate, with high levels of employment, because of the risk that displaced workers may not find alternative jobs. In addition, regulations that result in firms hiring workers, in order to ensure compliance, may have a positive effect on employment.

During sustained periods of excess unemployment, the opportunity cost of labor required by regulated sectors to bring their facilities into compliance with an environmental regulation may be lower than it would be during a period of full employment (particularly if regulated industries employ otherwise idled labor to design, fabricate, or install the pollution control equipment required under this final rule). Consistent with EO 13563, the EPA includes estimates of job impacts associated with the final rule. In the electricity sector, the EPA estimates that the net employment effect will range from -15,000 to +30,000 jobs, with a central estimate of +8,000. The EPA also presents an estimate of short-term employment effects

as a result of increased demand for pollution control equipment.

The results of this analysis, found in Chapter 6 of the RIA, indicate that the final rule has the potential to provide increases in short-term employment in the environmental industry, primarily driven by the high demand for new pollution control equipment. Overall, the results suggest that the final rule could support a net of roughly 46,000 job years[355] in direct employment impacts in 2015.

There are other employment effects that cannot be estimated quantitatively at this time. The employment gains related to the new pollution controls are likely to be tempered by some losses due to certain coal retirements. On the other hand, some of those workers who lose their jobs due to plant retirements could find alternative employment operating the replacement electricity generating equipment or new pollution controls at nearby units. Finally, job losses due to reduced coal demand may be offset by job gains due to increased natural gas demand, potentially resulting in a positive net change in employment due to fuel demand changes.

The basic approach to estimate these employment impacts involved using IPM projections from the final rule analysis, in particular the amount of existing coal-fired capacity that is projected to be retrofit with pollution control technologies. These data, along with data on labor and resource needs of new pollution

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[355] Numbers of job years are not the same as numbers of individual jobs, but represents the amount of work that can be performed by the equivalent of one full-time individual for a year (or FTE). For example, 25 job years may be equivalent to five full-time workers for five years, 25 full-time workers for one year, or one full-time worker for 25 years.

controls and labor productivity from engineering studies and secondary sources, are used to estimate employment impacts for the pollution control industry in 2015. For more information, please refer to Chapter 6 and appendix 6B in the RIA.

The EPA relied on Morgenstern, *et al.*, (2002), to identify three economic mechanisms by which pollution abatement activities can influence jobs in the regulated sector separately from the short-term employment effects:

[] Higher production costs raise market prices, higher prices reduce consumption, and employment within an industry falls ("demand effect");

[] Pollution abatement activities require additional labor services to produce the same level of output ("cost effect"); and

[] Post-regulation production technologies may be more or less labor intensive (i.e., more/less labor is required per dollar of output) ("factor-shift effect").

Using plant-level Census information between the years 1979 and 1991 Morgenstern,*et al.*, estimate the size of each effect for four polluting and regulated industries (petroleum, plastic material, pulp and paper, and steel). On average across the four industries, each additional $ 1 million spent on pollution abatement results in a small net increase of 1.55 jobs; the estimated effect is not a statistically different from zero. As a result, the authors conclude that increases in pollution abatement expenditures may increase employment in the relevant sectors and do not necessarily cause economically significant employment changes. The conclusion is similar to that of Berman and Bui (2001) who found that increased air quality

regulation in Los Angeles did not cause large employment changes.[356] For more information, please refer to Chapter 6 of the RIA for this final rule.[357]

In the directly affected sector, the EPA estimates that the net employment effect will range from -15,000 to +30,000 jobs, with a central estimate of +8,000. The ranges of job effects for the electricity sector, as calculated using the Morgenstern,*et al.*, approach are listed in Table 8.

Table 8--Range of Job Effects for the Electricity Sector

	Estimates using Morgenstern, et al., (2001)			
	Demand effect	Cost effect	Factor shift effect	Net effect
Change in Full-Time Jobs per Million Dollars of Environmental Expenditure <a>	-3.56	2.42	2.68	1.55.
Standard Error	2.03	0.83	1.35	2.24.
EPA estimate for Final Rule <b>	-39,000 to +2,000	+4,000 to +21,000	+200 to +27,000	-15,000 to +30,000.

[356] For alternative views in economic journals, see Henderson (1996) and Greenstone (2002).

[357] It should be noted that if more labor must be used to produce a given amount of output, then this implies a decrease in labor productivity. A decrease in labor productivity will cause a short-run aggregate supply curve to shift to the left, and businesses will produce less, all other things being equal.

fna Expressed in 1987 dollars. See footnote a from Table 6-2 of the RIA for inflation adjustment factor used in the analysis.

fnb According to the 2007 Economic Census, the electric power generation, transmission and distribution sector (NAICS 2211) had approximately 510,000 paid employees.

The EPA recognizes there may be other job effects that are not considered in the Morgenstern,*et al.*, study. Although EPA has considered some economy-wide changes, we do not have sufficient information to quantify other job effects associated with this rule.

E. What are the benefits of this final rule?

1. Benefits of Reducing HAP Emissions

a. Human Health and Environmental Effects Due to Exposure to MeHg. In this section, we provide a qualitative description of human health and environmental effects due to exposure to MeHg. The NAS Study (NRC, 2000) provides a thorough review of the effects of MeHg on human health. Many of the peer-reviewed articles cited in this section are publications originally cited in the NAS Study. In addition, the EPA has conducted literature searches to obtain other related and more recent publications to complement the material summarized by the NAS in 2000.

b. Neurologic Effects of Exposure to MeHg. In its review of the literature, the NAS found neurodevelopmental effects to be the most sensitive and best documented endpoints and concluded that they are appropriate for establishing an RfD (NRC, 2000); in particular NAS supported the use of results from neurobehavioral or neuropsychological tests. The NAS Study (NRC, 2000) noted that studies in animals reported sensory effects as well as effects on brain development and memory functions and support the conclusions based on epidemiology studies. The NAS

noted that their recommended neurodevelopmental endpoints for an RfD are associated with the ability of children to learn and to succeed in school. They concluded the following: "The population at highest risk is the children of women who consumed large amounts of fish and seafood during pregnancy. The committee concludes that the risk to that population is likely to be sufficient to result in an increase in the number of children who have to struggle to keep up in school."

c. Cardiovascular Impacts of Exposure to MeHg. The NAS summarized data on cardiovascular effects available up to 2000. Based on these and other studies, the NAS Study concluded that "Although the data base is not as extensive for cardiovascular effects as it is for other end points (*i.e.*, neurologic effects) the cardiovascular system appears to be a target for MeHg toxicity in humans and animals." The report also stated that "additional studies are needed to better characterize the effect of MeHg exposure on blood pressure and cardiovascular function at various stages of life."

Additional cardiovascular studies have been published since 2000. The EPA did not develop a quantitative dose-response assessment for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects. In addition, there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. The pharmacokinetics of some of the exposure measures (such as toenail Hg levels) are not well understood. The studies have not yet received the review and scrutiny of the more well-established neurotoxicity data base.

d. Genotoxic Effects of Exposure to MeHg. The Mercury Study noted that MeHg is not a potent mutagen but is capable of causing chromosomal damage in a number of experimental systems. The NAS Study indicated that evidence that human exposure to MeHg causes genetic damage is inconclusive; they note that some earlier studies showing chromosomal damage in lymphocytes may not have controlled sufficiently for potential confounders. One study of adults living in the Tapajos River region in Brazil (Amorim*et al.*, 2000) reported a direct relationship between MeHg concentration in hair and DNA damage in lymphocytes, as well as effects on chromosomes. Long-term MeHg exposures in this population were believed to occur through consumption of fish, suggesting that genotoxic effects (largely chromosomal aberrations) may result from dietary, chronic MeHg exposures similar to and above those seen in the populations studied in the Faroe Islands and Republic of Seychelles.

e. Immunotoxic Effects to Exposure to MeHg. Although exposure to some forms of Hg can result in a decrease in immune activity or an autoimmune response (ATSDR, 1999), evidence for immunotoxic effects of MeHg is limited (NRC, 2000).

f. Other Hg-Related Human Toxicity Data. Based on limited human and animal data, MeHg is classified as a "possible" human carcinogen by the International Agency for Research on Cancer (IARC, 1994) and in IRIS (USEPA, 2002). The existing evidence supporting the possibility of carcinogenic effects in humans from low-dose chronic exposures is tenuous. Multiple human epidemiological studies have found no significant association between Hg exposure and overall cancer incidence, although a few studies have shown an association between Hg

exposure and specific types of cancer incidence (*e.g.*, acute leukemia and liver cancer) (NAS, 2000).

Some evidence of reproductive and renal toxicity in humans from MeHg exposure exists. However, overall, human data regarding reproductive, renal, and hematological toxicity from MeHg are very limited and are based on studies of the two high-dose poisoning episodes in Iraq and Japan or animal data, rather than epidemiological studies of chronic exposures at the levels of interest in this analysis.

g. Ecological Effects of Hg. Deposition of Hg to watersheds can also have an impact on ecosystems and wildlife. Mercury contamination is present in all environmental media, with aquatic systems experiencing the greatest exposures due to bioaccumulation. Bioaccumulation refers to the net uptake of a contaminant from all possible pathways and includes the accumulation that may occur by direct exposure to contaminated media as well as uptake from food.

A review of the literature on effects of Hg on fish[358] reports results for numerous species including trout, bass (large and smallmouth), northern pike, carp, walleye, salmon, and others from laboratory and field studies. The effects of MeHg in fish are reproductive in nature. Although we cannot determine at this time whether these reproductive deficits are affecting fish populations across the U.S. it should be noted that it would seem reasonable that over time reproductive deficits would have an effect on populations.

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[358] Crump, KL, and Trudeau, VL. Mercury-induced reproductive impairment in fish. Environmental Toxicology and Chemistry. Vol. 28, No. 5, 2009.

Mercury also affects avian species. In previous reports[359] much of the focus has been on large piscivorous species, in particular the common loon. According to Evers,*et al.*, significant adverse effects from Hg on breeding loons have been found to occur, including behavioral (reduced nest-sitting), physiological (flight feather asymmetry) and reproductive (chicks fledged/territorial pair) effects and reduced survival.[360] Additionally, Evers, *et al.*, (*See* footnote 5), believe that the weight of evidence indicates that population-level effects occur in parts of Maine and New Hampshire, and potentially in broad areas of the loon's range.

Recently, attention has turned to other piscivorous species such as the white ibis and great snowy egret. These wading birds have a very wide diet including crayfish, crabs, snails, insects and frogs. White ibis have been observed to have decreased foraging

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[359] U.S. Environmental Protection Agency (EPA). 1997. Mercury Study Report to Congress. Volume V: Health Effects of Mercury and Mercury Compounds. EPA-452/R-97-007. U.S. EPA Office of Air Quality Planning and Standards, and Office of Research and Development; U.S. Environmental Protection Agency (U.S. EPA). 2005. *Regulatory Impact Analysis of the Final Clean Air Mercury Rule.* Research Triangle Park, NC., March; EPA report no. EPA-452/R-05-003. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/mercury_ria_final.pdf.*

[360] Evers, DC, Savoy, LJ, DeSorbo, CR, Yates, DE, Hanson, W, Taylor, KM, Siegel, LS, Cooley, JH, Jr., Bank, MS, Major, A, Munney, K, Mower, BF, Vogel, HS, Schoch, N, Pokras, M, Goodale, MW, Fair, J. Adverse effects from environmental mercury loads on breeding common loons. Ecotoxicology. 17:69-81, 2008; Mitro, MG, Evers, DC, Meyer, MW, and Piper, WH. Common loon survival rates and mercury in New England and Wisconsin. Journal of Wildlife Management. 72(3): 665-673, 2008.

efficiency[361] and have been shown to exhibit decreased reproductive success and altered pair behavior.[362] In egrets, Hg has been implicated in the decline of the species in south Florida,[363] and Hoffman[364] has shown that egrets exhibit liver and possibly kidney effects. Although ibises and egrets are most abundant in coastal areas and these studies were conducted in south Florida and Nevada, the ranges of ibises and egrets extend to a large portion of the U.S.

Insectivorous birds have also been shown to suffer adverse effects due to Hg exposure. Songbirds such as Bicknell's thrush, tree swallows, and the great tit have shown reduced reproduction, survival, and changes in singing behavior. Exposed tree swallows produced

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[361] Adams, EM, and Frederick, PC. Effects of methylmercury and spatial complexity on foraging behavior and foraging efficiency in juvenile white ibises (Eudocimus albus). Environmental Toxicology and Chemistry. Vol 27, No. 8, 2008.

[362] Frederick, P, and Jayasena, N. Altered pairing behavior and reproductive success in white ibises exposed to environmentally relevant concentrations of methylmercury. Proceedings of The Royal Society B. doi: 10-1098, 2010.

[363] Sepulveda, MS, Frederick, PC, Spalding, MG, and Williams, GE, Jr. Mercury contamination in free-ranging great egret nestlings (Ardea albus) from southern Florida, USA. Environmental Toxicology and Chemistry. Vol. 18, No. 5, 1999.

[364] Hoffman, DJ, Henny, CJ, Hill, EF, Grover, RA, Kaiser, JL, Stebbins, KR. Mercury and drought along the lower Carson River, Nevada: III. Effects on blood and organ biochemistry and histopathology of snowy egrets and black-crowned night-herons on Lahontan Reservoir, 2002-2006. Journal of Toxicology and Environmental Health, Part A. 72: 20, 1223-1241, 2009.

fewer fledglings,[365] had lower survival rates,[366] and had compromised immune competence.[367] The great tit has exhibited reduced singing behavior and smaller song repertoire in areas of high contamination.[368]

In mammals, adverse effects have been observed in mink and river otter, both fish eating species. For otter from Maine and Vermont, maximum concentrations of Hg in fur nearly equal or exceed a level associated with mortality and concentration in liver for mink in Massachusetts/Connecticut and the levels in fur from mink in Maine exceed concentrations associated with acute mortality.[369] Adverse sublethal effects may be associated with lower Hg concentrations and consequently may be more widespread than potential acute effects. These effects may include increased activity, poorer maze performance, abnormal startle reflex, and impaired escape and avoidance behavior.[370]

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[365] Brasso, RL, and Cristol, DA. Effects of mercury exposure in the reproductive success of tree swallows (Tachycineta bicolor). Ecotoxicology. 17:133-141, 2008.

[366] Hallinger, KK, Cornell, KL, Brasso, RL, and Cristol, DA. Mercury exposure and survival in free-living tree swallows (Tachycineta bicolor). Eotoxicology. Doi: 10.1007/s10646-010-0554-4, 2010.

[367] Hawley, DM, Hallinger, KK, Cristol, DA. Compromised immune competence in free-living tree swallows exposed to mercury. Ecotoxicology. 18:499-503, 2009.

[368] Gorissen, L, Snoeijs, T, Van Duyse, E, and Eens, M. Heavy metal pollution affects dawn singing behavior in a small passerine bird. Oecologia. 145: 540-509, 2005.

[369] Yates, DE, Mayack, DT, Munney, K, Evers DC, Major, A, Kaur, T, and Taylor, RJ. Mercury levels in mink (Mustela vison) and river otter (Lonra canadensis) from northeastern North America. Ecotoxicology. 14, 263-274, 2005.

[370] Scheuhammer, AM, Meyer MW, Sandheinrich, MB, and Murray, MW. Effects of environmental methylmercury on the

h. Methodology for Partial Hg Benefits Estimation. The EPA has conducted a national-scale analysis of the benefits to recreational anglers of avoided IQ loss related to reductions of Hg emissions and subsequent deposition that will be achieved by this rule. Because the primary measurable health effect of concern--developmental neurological abnormalities in children--occurs as a result of in-utero exposures to Hg, the specific population of interest in this case is prenatally exposed children. To identify and estimate the size of this exposed population, the benefits analysis focused on pregnant women in freshwater recreational angler households. Estimating Hg exposures for this exposure pathway and population of interest requires three main components: (1) The size of the exposed population of interest (annual number of pregnant women in freshwater angler households during the year), (2) the average concentration of MeHg in noncommercial freshwater fish filets consumed, and (3) the average daily consumption rate of noncommercial freshwater fish. The Hg concentrations of fish in the waterbodies where the fish are caught are modeled using Mercury Maps to project the decline in concentrations due to the rule. To approximate the percentage of freshwater fishing trips (and exposed individuals) from each Census tract matched to each waterbody type, the EPA used state-level averages. These averages were calculated for each state, based on the portion of residents' freshwater fishing trips that are to each waterbody type, based on 2001 National Survey of Fishing, Hunting, and Wildlife-Associated Recreation (FHWAR) data.

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health of wild birds, mammals, and fish. Ambio. Vol.36, No.1, 2007.

Data from the 1994 National Survey on Recreation and the Environment (NSRE) were used to approximate the percentage of freshwater fishing trips (and exposed individuals) matched to different distances from anglers' residential location.

To determine an appropriate daily fish consumption rate for the analysis, the EPA conducted an extensive review of existing literature characterizing self-caught freshwater fish consumption. Based on this review, it was decided that the ingestion rates for recreational freshwater fishers, specified as "recommended" in the EPA's "Environmental Exposure Factors Handbook" (EPA, 1997), represented the most appropriate values to use in this analysis.

Estimating the IQ decrements in children that result from mothers' prenatal ingestion of Hg from fish required two steps. First, based on the estimated average daily maternal ingestion rate, the expected Hg concentration in the hair of exposed pregnant women was estimated. Second, to estimate the expected IQ decrement in offspring, the following dose-response relationship was developed based on the summary findings reported in Axelrad *et al.*, (2007).

The valuation approach used to assess monetary losses due to IQ decrements is based on an approach applied in previous EPA analyses (EPA, 2008). The approach expresses the potential loss to an affected individual resulting from IQ decrements in terms of foregone future earnings (net of changes in education costs) for that individual.

The estimate for "Present Value of Lifetime Earnings" is derived using earnings and labor force participation rate data from the Bureau of Labor Statistics 2006 Current Population Survey. Estimates

of the average effect of a 1-point increase in IQ on lifetime earnings range from a 1.76 percent increase (Schwartz, 1994) to a 2.379 percent increase (Salkever, 1995). The percentage increases in the two studies reflect both the direct impact of IQ on hourly wages and indirect effects on annual earnings as the result of additional schooling and increased labor force participation. The estimate for years of additional schooling is based on Schwartz (1994), who reports an increase of 0.131 years of schooling per IQ point.

In addition to this positive net effect on earnings, an increase in IQ is also assumed to have a positive effect on the amount of time spent in school and on associated costs. To incorporate (1) uncertainty regarding the size of the percentage change in future earnings and (2) different assumptions regarding the discount rate, the resulting value estimates for the average net loss per IQ point decrement are expressed as a range. Assuming a 3 percent discount rate, value IQ ranges from $ 8,013 (using the Schwartz estimates) to $ 11,859 (using the Salkever estimates) in increased earnings per year per 1-point IQ increase. With a 7 percent discount rate assumption, the value IQ estimates range from $ 893 to $ 1,958 in increased earnings per year per 1-point IQ increase.

The EPA analyzed the aggregate national IQ and present-value loss estimates for two base case and three emission control scenarios. The highest losses are estimated for the 2005 base case. For the population of prenatally exposed children included in the analysis (almost 240,000), Hg exposures under baseline conditions during the year 2005 are estimated to have resulted in more than 25,500 IQ points lost. Assuming a 3 percent discount rate, the present-year value of these losses ranges from $ 204.8

million to $ 292.5 million nationally.[371] These losses represent expected present value of declines in future net earnings over the entire lifetimes of the children who are prenatally exposed during the year 2005. With a 7 percent discount rate, the present-year value range is considerably lower: $ 22.8 million to $ 50.0 million.

For this rule, the EPA generated estimates of aggregate nationwide benefits associated with reductions in Hg exposures and resulting reductions in IQ losses. Most importantly, the benefits of the 2016 MATS scenario (relative to the 2016 base case) are estimated to range between $ 4 million and $ 6 million (assuming a 3 percent discount rate), because of an estimated 511 point reduction in IQ losses. The EPA recognizes that these calculated benefits are a small subset of the benefits of reducing Hg emissions.

2. Health and Welfare Co-Benefits

Emission controls installed to meet the requirements of this rule will generate co-benefits by reducing criteria pollutants including $PM_{2.5}$ and SO_2, as well as CO_2. For this rule, we were only able to estimate the mortality benefits of $PM_{2.5}$ reductions due to changes in emissions of SO_2 and direct $PM_{2.5}$ and climate benefits resulting from CO[2] reductions. Additional co-benefits may result from decreases in $PM_{2.5}$ morbidity impacts, decreases in sulfur deposition and direct

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[371] Monetized benefits estimates are for an immediate change in MeHg levels in fish. If a lag in the response of MeHg levels in fish were assumed, the monetized benefits could be significantly lower, depending on the length of the lag and the discount rate used. As noted in the discussion of the Mercury Maps modeling, the relationship between deposition and fish tissue MeHg is proportional in equilibrium, but the Mercury Maps approach does not provide any information on the time lag of response.

health effects of SO_2, and improvements in visibility in national parks and wilderness areas. Total co-benefits may be higher than the partial estimates of co-benefits provided here. Our best estimate of the monetized health and climate co-benefits of this rule in 2016 at a 3 percent discount rate are $ 37 billion to $ 90 billion or $ 33 billion to $ 81 billion at a 7 percent discount rate (2007]. Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower health co-benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates.[372]

a. Human Health Co-Benefits. To estimate the human health co-benefits of this rule, the EPA used benefit-per-ton factors to quantify the changes in $PM_{2.5}$ -related health impacts and monetized benefits based on changes in SO_2 and direct $PM_{2.5}$ emissions. These benefit-per-ton factors were based on an interim baseline and policy scenario for which full-scale ambient air quality modeling and air quality-based human health benefits assessments were performed. This general approach and methodology is laid out in Fann, *et al.*, (2009),[373] but for this rule the air quality modeling used a better spatial representation of the emission changes from EGUs. Using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. For more details on the creation of the benefit-per-ton factors and their

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[372] Roman, *et al.*, 2008. Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S. Environ. Sci. Technol., 42, 7, 2268-2274.

[373] Fann, N., C.M. Fulcher, B.J. Hubbell. 2009. "The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution." Air Qual Atmos Health (2009) 2:169-176.

application to emission reductions under this rule, please refer to the RIA for this rule in the docket.

Table 9 presents the estimates of reduced annual incidence of $PM_{2.5}$ -related health effects in 2016 resulting from this rule. Table 10 presents the estimated annual monetary value of the reduced incidence of quantified health endpoints in 2016 resulting from this rule.

The reduction in premature fatalities each year accounts for between 93 and 97 percent of the estimated health co-benefits that were monetized.

Table 9--Estimated Reductions in Incidence of PM[2.5]-Related Health Effects in 2016 <a>

Health effect	Number of reduced cases
Adult Premature Mortality	
Pope et al., (2002) (age >30)	4,200. (1,200 to 7,200).
Laden et al., (2006) (age >25)	11,000. (5,000 to 17,000).
Infant Premature Mortality (<1 year)	20. (-22 to 61).
Chronic Bronchitis	2,800. (88 to 5,600).
Non-fatal heart attacks (age >18)	4,700. (1,200 to 8,300).
Hospital admissions--respiratory (all ages)	830. (330 to 1,300).
Hospital admissions--cardiovascular (age >18)	1,800. (1,200 to 2,200).
Emergency room visits for asthma (age <18)	3,100. (1,600 to 4,700).
Acute bronchitis (age 8-12)	6,300.

Table 9--Estimated Reductions in Incidence of PM[2.5]-Related Health Effects in 2016 <a>

Health effect	Number of reduced cases
Lower respiratory symptoms (age 7-14)	(-1,400 to 14,000). 80,000. (31,000 to 130,000).
Upper respiratory symptoms (asthmatics age 9-11)	60,000. (11,000 to 110,000).
Asthma exacerbation (asthmatics 6-18)	130,000. (4,500 to 450,000).
Lost work days (ages 18-65)	540,000. (460,000 to 620,000).
Minor restricted-activity days (ages 18-65)	3,200,000. (2,600,000 to 3,800,000).

fna Values rounded to two significant figures. Co-benefits from reducing exposure to ozone, other criteria pollutants, and HAP, as well as reducing visibility impairment and ecosystem effects are not included here.

Table 10--Estimated Monetary Value (Billions 2007) of PM[2.5]-Related Health Benefits in 2016 fna

Health effect	Monetized benefits
Adult Premature Mortality	
Pope, et al., (2002) (age >30):	
3% discount rate	$ 34. ($ 2.6 to $ 100).
7% discount rate	$ 30. ($ 2.4 to $ 92).
Laden, et al., (2006) (age >25):	
3% discount rate	$ 87.

Table 10--Estimated Monetary Value (Billions 2007] of PM[2.5]-Related Health Benefits in 2016 fna

Health effect	Monetized benefits
	($ 7.5 to $ 250).
7% discount rate	$ 78.
	($ 6.8 to $ 230).
Infant Premature Mortality (<1 year)	$ 0.2.
	($-0.2 to $ 0.8).
Chronic Bronchitis	$ 1.4.
	($ 0.1 to $ 6.4).
Non-fatal heart attacks (age >18):	
3% discount rate	$ 0.5.
	($ 0.1 to $ 1.3).
7% discount rate	$ 0.4.
	($ 0.1 to $ 1.0).
Hospital admissions--respiratory (all ages)	$ 0.01.
	($ 0.01 to $ 0.02).
Hospital admissions--cardiovascular (age >18)	$ 0.03.
	(<$ 0.01 to $ 0.05).
Emergency room visits for asthma (age <18)	<$ 0.01.
Acute bronchitis (age 8-12)	<$ 0.01.
Lower respiratory symptoms (age 7-14)	<$ 0.01.
Upper respiratory symptoms (asthmatics age 9-11)	<$ 0.01.
Asthma exacerbation (asthmatics 6-18)	<$ 0.01.
Lost work days (ages 18-65)	$ 0.1.
	($ 0.1 to $ 0.1).
Minor restricted-activity days (ages 18-65)	$ 0.2.
	($ 0.1 to $ 0.3).
Monetized Health Co-Benefits	
Pope, et al., (2002):	
3% discount rate	$ 36.
	($ 2.8-$ 110).
7% discount rate	$ 33.
	($ 2.5-$ 100).
Laden, et al., (2006):	
3% discount rate	$ 89.

Table 10--Estimated Monetary Value (Billions 2007] of PM[2.5]-Related Health Benefits in 2016 fna

Health effect	Monetized benefits
	($ 7.7-$ 260).
7% discount rate	$ 80.
	($ 6.9-$ 240).

fna Values rounded to two significant figures. Co-benefits from reducing exposure to ozone, other criteria pollutants, and HAP, as well as reducing visibility impairment and ecosystem effects are not included here.

It is important to note that the magnitude of the $PM_{2.5}$ co-benefits is largely driven by the concentration response function for premature mortality. Experts have advised the EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between PM[2.5] concentrations and premature mortality. We cite two key empirical studies, one based on the American Cancer Society cohort study[374] and the other based on the extended Six Cities cohort study.[375] The analyses upon which this rule is based were selected from the peer-reviewed scientific literature. We used up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

Every benefit analysis examining the potential effects of a change in environmental protection

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[374] Pope *et al.*, 2002. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." Journal of the American Medical Association. 287:1132-1141.

[375] Laden*et al.*, 2006. "Reduction in Fine Particulate Air Pollution and Mortality." American Journal of Respiratory and Critical Care Medicine. 173:667-672.

requirements is limited to some extent by data gaps, model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Gaps in the scientific literature often result in the inability to estimate quantitative changes in health and environmental effects, or to assign economic values even to those health and environmental outcomes that can be quantified. The uncertainties in the underlying scientific and economics literature (that may result in overestimation or underestimation of the co-benefits) are discussed in detail in the RIA. Despite these uncertainties, we believe the benefit analysis for this rule provides a reasonable indication of the expected health co-benefits of the rulemaking in future years under a set of reasonable assumptions.

When characterizing uncertainty in the PM-mortality relationship, the EPA has historically presented a sensitivity analysis applying alternate assumed thresholds in the PM concentration-response relationship. In its synthesis of the current state of the PM science, the EPA's 2009 Integrated Science Assessment for Particulate Matter concluded that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship.

In the RIA accompanying this rulemaking, rather than segmenting out impacts predicted to be associated with levels above and below a "bright line" threshold, the EPA includes a "lowest measured level" (LML) analysis that illustrates the increasing uncertainty that characterizes exposure attributed to levels of $PM_{2.5}$ below the LML of each epidemiological study used to estimate $PM_{2.5}$ -related premature death. Fig-

ures provided in the RIA show the distribution of baseline exposure to $PM_{2.5}$, as well as the lowest air quality levels measured in each of the epidemiology cohort studies. This information provides a context for considering the likely portion of PM-related mortality benefits occurring above or below the LML of each study; in general, our confidence in the size of the estimated reduction in $PM_{2.5}$ related premature mortality diminishes as baseline concentrations of $PM_{2.5}$ are lowered.

Based on the modeled interim baseline which is approximately equivalent to the final baseline (*See* Appendix A of the RIA), 11 percent and 73 percent of the estimated avoided mortality impacts occur at or above an annual mean $PM_{2.5}$ level of 10 [mu]g/m3 (the LML of the Laden*et al.*, 2006 study)or 7.5 [mu]g/m3 (the LML of the Pope,*et al.*, 2002 study), respectively. Although the LML analysis provides some insight into the level of uncertainty in the estimated PM mortality benefits, the EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations. A large fraction of the $PM_{2.5}$ -related benefits occur below the level of the National Ambient Air Quality Standard (NAAQS) for $PM_{2.5}$ at 15 [mu]g/m3, which was set in 2006. It is important to emphasize that NAAQS are not set at a level of zero risk. Instead, the NAAQS reflect the level determined by the Administrator to be protective of public health within an adequate margin of safety, taking into consideration effects on susceptible populations. While benefits occurring below the standard may be less certain than those occurring above the standard, EPA considers them to be legitimate components of the total benefits estimate.

It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Benefits are shown as a range from Pope, *et al.*, (2002), to Laden, *et al.*, (2006). These studies assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between directly-emitted particles (carbonaceous and crustal particles) and SO[2] emissions that form sulfate particles, based on the location of emission changes and magnitude of population exposure changes. Regardless, however, the assumption that all fine particles are equally potent in causing premature mortality adds uncertainty to the benefits estimate.

b. Non-Climate Welfare Co-Benefits. Emission controls installed to comply with the requirements specified in this rule will also generate co-benefits by improving visibility. We anticipate that improvements in visibility in Class I areas as well as residential areas where people live, work, and recreate could be substantial. Because full-scale air quality modeling was not performed for this rule, we are unable to quantify these visibility co-benefits for this rule. However, the estimated value of visibility benefits calculated from the modeled interim baseline and policy scenario was $ 1.1 billion (in 2007]. These visibility benefits are not included in the total co-benefits estimate of the final policy scenario used as a basis for this final rule. The distribution of emission reductions did not change substantially in the visibility regions studied, therefore visibility benefits

of the final policy scenario are likely to be of a similar magnitude.

Ecosystem and other welfare effects include reduced acidification and, in the case of NO[X], eutrophication of water bodies; possible reduced nitrate contamination of drinking water; ozone vegetation damage; a reduction in the role of sulfate in Hg methylation; and reduced acid and particulate deposition that causes damages to cultural monuments, as well as soiling and other materials damage. To illustrate the important nature of benefit categories the EPA is currently unable to monetize, we discuss the potential public welfare and environmental impacts related to reductions in emissions required by this rule in the RIA, including reduced visibility impairment, reduced effects from acid deposition, reduced effects from nutrient enrichment, and reduced vegetation effects from ambient exposure to SO_2 and NO_2.

c. Climate co-benefits. This rule is expected to reduce CO_2 emissions from the electricity sector. The EPA has assigned a dollar value to reductions in CO_2 emissions using recent estimates of the "social cost of carbon" (SCC). The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year or the per metric ton benefit estimate relating to decreases in CO_2 emissions. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damage from increased flood risk, and the value of ecosystem services due to climate change.

The SCC estimates used in this analysis were developed through an interagency process that included the EPA and other executive branch entities, and that concluded in February 2010. We first used

these SCC estimates in the benefits analysis for the final joint EPA/DOT Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; see the rule's preamble for discussion about application of the SCC *(75 FR 25324;* May 7, 2010). The SCC Technical Support Document (SCC TSD) provides a complete discussion of the methods used to develop these SCC estimates. n376

n376 Docket ID EPA-HQ-OAR-2009-0472-114577, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at *http://epa.gov/otaq/climate/ regulations.htm.*

The interagency group selected four SCC values for use in regulatory analyses, which we have applied in this analysis: $ 5.9, $ 24.3, $ 39, and $ 74.4 per metric ton of CO_2 emissions in 2016, in 2007 dollars. The first three values are based on the average SCC from three integrated assessment models, at discount rates of 5, 3, and 2.5 percent, respectively. Social cost of carbon values at several discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context. The fourth value is the 95th

percentile of the SCC from all three values at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the extremes of the SCC distribution. Low probability, high impact events are incorporated into all of the SCC values through explicit consideration of their effects in two of the three values as well as the use of a probability density function for equilibrium climate sensitivity. Treating climate sensitivity probabilistically results in more high temperature outcomes, which in turn leads to higher projections of damages.

Applying the global SCC estimates using a 3 percent discount rate, we estimate the value of the climate related benefits of this rule in 2016 is $ 360 million (2007], as shown in Table 11. See the RIA for more detail on the methodology used to calculate these benefits and additional estimates of climate benefits using different discount rates and the 95th percentile of the 3 percent discount rate SCC. Important limitations and uncertainties of the SCC approach are also described in the RIA.

Table 11--Estimated Monetary Value (Billions 2007] of PM[2.5]-Related Health Benefits and Climate Benefits in 2016 fna

Effect	Monetized benefits
Monetized Health Co-Benefits	
Pope, et al., (2002):	
3% discount rate	$ 36 ($ 2.8-$ 110)
7% discount rate	$ 33 ($ 2.5-$ 100)
Laden, et al., (2006):	
3% discount rate	$ 89

Table 11--Estimated Monetary Value (Billions 2007] of PM[2.5]-Related Health Benefits and Climate Benefits in 2016 fna

Effect	Monetized benefits
7% discount rate	($ 7.7-$ 260)
	$ 80
	($ 6.9-$ 240)
Climate-related Co-Benefits (3% discount rate)	$ 0.36
Monetized Total Co-Benefits	
Pope, et al., (2002):	
3% discount rate	$ 37
	($ 3.2-$ 110)
7% discount rate	$ 33
	($ 2.9-$ 100)
Laden, et al., (2006):	
3% discount rate	$ 90
	($ 8.0-$ 260)
7% discount rate	$ 81
	($ 7.3-$ 240)

fna Values rounded to two significant figures. Co-benefits from reducing exposure to ozone, other criteria pollutants, and HAP, as well as reducing visibility impairment and ecosystem effects are not included here.

Our best estimate for the monetized total health and climate co-benefits of this rule in 2016 at a 3 percent discount rate is between $ 37 billion and $ 90 billion or between $ 33 billion and $ 81 billion (2007] at a 7 percent discount rate. These estimates account for the quantified health and climate benefits described in Table 11.

XIII. Statutory and Executive Order Reviews

A. *Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review*

Under EO 12866 *(58 FR 51735;* October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $ 100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities. Accordingly, the EPA submitted this action to the OMB for review under Executive Orders 12866 and 13563 and any changes in response to OMB recommendations have been documented in the docket for this action. For more information on the costs and benefits for this rule, please refer to Table 2 of this preamble.

When estimating the human health benefits and compliance costs in Table 2 of this preamble, the EPA applied methods and assumptions consistent with the state-of-the-science for human health impact assessment, economics and air quality analysis. The EPA applied its best professional judgment in performing this analysis and believes that these estimates provide a reasonable indication of the expected benefits and costs to the nation of this rulemaking. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. In doing what is laid out above in this paragraph, the EPA adheres to EO 13563, "Improving Regulation and Regulatory Review," *(76 FR 3821;* January 18, 2011), which is a supplement to EO 12866.

In addition to estimating costs and benefits, EO 13563 focuses on the importance of a "regulatory system [that] * * * promote[s] predictability and reduce[s] uncertainty" and that "identify[ies] and use[s] the best, most innovative, and least burdensome

tools for achieving regulatory ends." In addition, EO 13563 states that "[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote such coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation." We recognize that the utility sector faces a variety of requirements, including ones under CAA section 110(a)(2)(D) dealing with the interstate transport of emissions contributing to ozone and PM air quality problems, with coal combustion wastes, and with the implementation of CWA section 316(b). In developing today's final rule, the EPA recognizes that it needs to approach these rulemakings in ways that allow the industry to make practical investment decisions that minimize costs in complying with all of the final rules, while still achieving the fundamentally important environmental and public health benefits that underlie the rulemakings.

A summary of the monetized costs, benefits, and net benefits for the final rule at discount rates of 3 percent and 7 percent is in Table 2 of this preamble. For more information on the analysis, please refer to the RIA for this rulemaking, which is available in the docket.

B. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the OMB under the Paperwork Reduction Act, *44 U.S.C. 3501* et seq. The Information Collection Request (ICR) document prepared by the EPA has been assigned EPA ICR number 2137.06.

The information collection requirements are not enforceable until OMB approves them. The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (*42 U.S.C. 7414*). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B. This final rule requires maintenance inspections of the control devices but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of 40 CFR part 63, subpart UUUUU. An affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in *40 CFR 63.2* (sudden, infrequent, not reasonable preventable, and not caused by poor maintenance and or careless operation) and where the source took necessary actions to minimize emissions. In addition, the source must meet certain notification and reporting requirements. For example, the source must prepare a written root cause analysis and submit

a written report to the Administrator documenting that it has met the conditions and requirements for assertion of the affirmative defense.

For this rule, EPA is adding affirmative defense to the estimate of burden in the ICR. To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, the EPA has provided administrative adjustments to this ICR that shows what the notification, recordkeeping, and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA's estimate for the required notification, reports, and records, including the root cause analysis, associated with a single incident totals approximately totals $ 3,141, and is based on the time and effort required of a source to review relevant data, interview plant employees, and document the events surrounding a malfunction that has caused an exceedance of an emission limit. The estimate also includes time to produce and retain the record and reports for submission to EPA. The EPA provides this illustrative estimate of this burden, because these costs are only incurred if there has been a violation, and a source chooses to take advantage of the affirmative defense.

The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense. Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the EPA

has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emissions events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of excess emissions caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, we believe the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small.

For this reason, we estimate no more than two such occurrences for all sources subject to 40 CFR part 63, subpart UUUUU over the 3-year period covered by this ICR. We expect to gather information on such events in the future, and will revise this estimate as better information becomes available.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $ 207.6 million. This includes 700,296 labor hours per year at a total labor cost of $ 49.1 million per year, annualized capital costs of $ 81.9 million, and annual operating and maintenance costs of $ 76.5 million. This estimate includes initial and annual performance tests, semiannual excess emission reports, developing a monitoring plan, notifications, and recordkeeping. All burden estimates are in 2007 dollars and represent the most cost

effective monitoring approach for affected facilities. Burden is defined at *5 CFR 1320.3(b)*.

An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for our regulations are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

B. Regulatory Flexibility Act, as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 et seq.

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business that is an electric utility producing 4 billion kilowatt-hours or less as defined by NAICS codes 221122 (fossil fuel-fired electric utility steam generating units) and 921150 (fossil fuel-fired electric utility steam generating units in Indian country); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000;

and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Pursuant to RFA section 603, the EPA prepared an initial regulatory flexibility analysis (IRFA) for the proposed rule and convened a Small Business Advocacy Review Panel to obtain advice and recommendations of representatives of the regulated small entities. A detailed discussion of the Panel's advice and recommendations is found in the Panel Report (EPA-HQ-OAR-2009-0234-2921). A summary of the Panel's recommendations is presented at *76 FR 24975*.

As required by RFA section 604, we also prepared a final regulatory flexibility analysis (FRFA) for the final rule. The FRFA addresses the issues raised by public comments on the IRFA, which was part of the proposal of this rule. The FRFA is summarized below and in the RIA.

1. Reasons Why Action Is Being Taken

In 2000, the EPA made a finding that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and listed EGUs pursuant to CAA section 112(c). On March 29, 2005 *(70 FR 15994)*, the EPA published a final rule (2005 Action) that removed EGUs from the list of sources for which regulation under CAA section 112 was required. That rule was published in conjunction with a rule requiring reductions in emissions of Hg from EGUs pursuant to CAA section 111, i.e., CAMR, May 18, 2005, *70 FR 28606)*. The 2005 Action was vacated on February 8, 2008, by the U.S. Court of Appeals for the District of Columbia Circuit. As a result of that vacatur, CAMR was also vacated and EGUs remain on

the list of sources that must be regulated under CAA section 112. This action provides the EPA's final NESHAP and NSPS for EGUs.

2. Statement of Objectives and Legal Basis for Final Rules

The MATS will protect air quality and promote public health by reducing emissions of HAP. In the December 2000 regulatory determination, the EPA made a finding that it was appropriate and necessary to regulate EGUs under CAA section 112. The February 2008 vacatur of the 2005 Action reverted the status of the rule to the December 2000 regulatory determination. Section 112(n)(1)(A) of the CAA and the 2000 determination do not differentiate between EGUs located at major versus area sources of HAP Thus, the NESHAP for EGUs will regulate units at both major and area sources. Major sources of HAP are those that have the potential to emit at least 10 tons per year (tpy) of any one HAP or at least 25 tpy of any combination of HAP. Area sources are any stationary sources of HAP that are not major sources.

3. Summary of Issues Raised During the Public Comment Process on the IRFA

The EPA received a number of comments related to the Regulatory Flexibility Act during the public comment process. A consolidated version of the comments received is reproduced below. These comments can also be found in their entirety in the response to comment document in the docket.

Comment: Several commenters expressed concern with the SBAR panel. Some believe Small Entity Representatives (SERs) were not provided with regulatory alternatives including descriptions of

significant regulatory options, differing timetables, or simplifications of compliance and reporting requirements, and subsequently were not presented with an opportunity to respond. One commenter believes the EPA's formal SBAR Panel notification and subsequent information provided by the EPA to the Panel did not include information on the potential impacts of the rule as required by CAA section 609(b)(1). Additional commenters suggested that the EPA's rulemaking schedule put pressure on the SBAR Panel through the abbreviated preparation for the Panel. Commenters also expressed concerns that the EPA did not provide participants more than cursory background information on which to base their comments. One commenter stated that the EPA did not provide deliberative materials, including draft proposed rules or discussions of regulatory alternatives, to the SBAR Panel members. One commenter stated the SBAR Panel Report does not meet the statutory obligation to recommend less burdensome alternatives. The commenter suggested the EPA panel members declined to make recommendations that went further than consideration or investigation of broad regulatory alternatives, with the exception of those recommendations in which the EPA rejected alternative interpretations of the CAA section 112 and relevant court cases. Two stated that the EPA did not respond to the concerns of the small business community, the SBA, or OMB, ignoring concerns expressed by the SER panelists. One commenter believes the EPA failed to convene required meetings and hearings with affected parties as required by law for small business entities. One commenter stated that the SERs' input is very important because more than 90 percent of public power utility systems meet the definition and qualify as small businesses under the SBREFA.

Response: The RFA requires that SBAR Panels collect advice and recommendations from SERs on the issues related to:

- The number and description of the small entities to which the proposed rule will apply;
- The projected reporting, recordkeeping and other compliance requirements of the proposed rule;
- Duplication, overlap or conflict between the proposed rule and other federal rules; and
- Alternatives to the proposed rule that accomplish the stated statutory objectives and minimize any significant economic impact on small entities.

The RFA does not require a covered agency to create or assemble information for SERs or for the government panel members. Although CAA section 609(b)(4) requires that the government Panel members review any material the covered agency has prepared in connection with the RFA, the law does not prescribe the materials to be reviewed. The EPA's policy, as reflected in its RFA guidance, is to provide as much information as possible, given time and resource constraints, to enable an informed Panel discussion. In this rulemaking, because of a court-ordered deadline, the EPA was unable to hold a pre-panel meeting but still provided SERs with the information available at the time, held a standard Panel Outreach meeting to collect verbal advice and recommendations from SERs, and provided the standard 14-day written comment period to SERs. The EPA received substantial input from the SERs, and the Panel report describes recommendations made by the Panel on measures the Administrator should

consider that would minimize the economic impact of the proposed rule on small entities. The EPA complied with the RFA. In addition, we met with representatives of small businesses, small rural cooperatives, and small governments a number of times during the regulatory development process to discuss their issues and concerns regarding the proposed MATS rule for EGUs.

Comment: One commenter requested that the EPA work with utilities such that new regulations are as flexible and cost efficient as possible.

Response: In developing the final rule, the EPA has considered all information provided prior to, as well as in response to, the proposed rule. The EPA has endeavored to make the final regulations flexible and cost-efficient while adhering to the requirements of the CAA. The final rule includes a number of flexibilities, such as those related to monitoring requirements, that will lower costs and simplify compliance for small businesses and local governments.

Comment: One commenter was concerned about the ability of small entities or nonprofit utilities such as those owned and/or operated by rural electric co-op utilities, and municipal utilities to comply with the proposed standards within 3 years. The commenter believes that the EPA disregarded the SER panelists who explained that under these current economic conditions they have constraints on their ability to raise capital for the construction of control projects and to acquire the necessary resources in order to meet a 3-year compliance deadline. Two commenters expressed concern that smaller utilities and those in rural areas will be unable to get vendors to respond to their requests for proposals, because they will be able to make more money serving larger utilities.

Response: The preamble to the proposed rule *(76 FR 25054;* May 3, 2011) provides a detailed discussion of how the EPA determined compliance times for the proposed (and final) rule. The EPA has provided pursuant to CAA section 112(i)(3)(A) the maximum 3-year period for sources to come into compliance. Sources may also seek a 1-year extension of the compliance period from their Title V permitting authority if the source needs that time to install controls. *See* CAA section 112(i)(3)(B). If the situation described by commenters (*i.e.*, where small entities or nonprofit utilities constraints on ability to raise capital for construction of control projects and to acquire necessary resources) results in the source needing additional time to install controls, they would be in a position to request the 1-year extension.

Comment: Several commenters believe the EPA did not adequately consider the disproportionately large impact on smaller generating units. The commenters note the diseconomies in scale for pollution controls for such units. One commenter noted the rule will create a more serious compliance hurdle for small communities that depend on coal-fired generation to meet their base load demand. The commenter notes that by not subcategorizing units, the EPA is dictating a fuel switch due to the disproportionately high cost on small communities. The other commenter believes the MACT and NSPS standards are unachievable by going too far without really considering the impacts on small municipal units, as public power is critical to communities, jobs, economic viability and electric reliability. A generating and transmissions electric cooperative which qualifies as a small entity believes the rule will ultimately result in increased electricity costs to its members and will negatively impact the economies of the primarily rural areas that they serve.

Another commenter believes there is no legal or factual basis for creating subcategories or weaker standards for state, tribal, or municipal governments or small entities that are operating obsolete units, particularly given the current market situation and applicable equitable factors. The commenter suggests both the EPA's and SBA's analyses focus exclusively on the effects on entities causing HAP emissions and primarily on those operating obsolete EGUs, and fail to consider either impacts on downwind businesses and governments or the positive impacts on small entities and governments owning and operating competing, clean and modern EGUs.

Response: The EPA disagrees with the commenters' belief that the impacts on smaller generating units were not adequately considered when developing the rule. The EPA determined the number of potentially impacted small entities and assessed the potential impact of the proposed action on small entities, including municipal units. A similar assessment was conducted in support of the final action. Specifically, the EPA estimated the incremental net annualized compliance cost, which is a function of the change in capital and operating costs, fuel costs, and change in revenue. The projected compliance cost was considered relative to the projected revenue from generation. Thus, the EPA's analysis accounts not only for the additional costs these entities face resulting from compliance, but also the impact of higher electricity prices. The EPA evaluated suggestions from SERs, including subcategorization recommendations. In the preamble to the proposed rule, the EPA explains that, normally, any basis for subcategorizing must be related to an effect on emissions, rather than some difference which does not affect emissions performance. The EPA does not see a distinction between

emissions from smaller generating units versus larger units. The EPA acknowledges the comment that there is no legal or factual basis for creating subcategories or weaker standards for state, tribal, or municipal governments or small entities that are operating obsolete units.

Comment: One commenter notes that the EPA recognizes LEEs in the rule such that they should receive less onerous monitoring requirements; however, the EPA does not recognize that small and LEEs also need and merit more flexible and achievable pollution control requirements. The commenter notes that the capital costs for emissions control at small utility units is disproportionately high due to inefficiencies in Hg removal, space constraints for control technology retrofits, and the fact that small units have fewer rate base customers across which to spread these costs. The commenter cites the Michigan Department of Environmental Quality report titled "Michigan's Mercury Electric Utility Workgroup, Final Report on Mercury Emissions from Coal-Fired Power Plants," (June 2005). The commenter notes that the EPA has addressed such concerns previously, citing the RIA for the 1997 8-hour ozone standard. The commenter also suggests smaller utility systems generally have less capital to invest in pollution control than larger, investor-owned systems, due to statutory inability to borrow from the private capital markets, statutory debt ceilings, limited bonding capacity, borrowing limitations related to fiscal strain posed by other, non-environmental factors, and other limitations.

Response: The EPA acknowledges that the rule contains reduced monitoring requirements for existing units that qualify as LEEs. Although the EPA does not

believe that reduced pollution control requirements are warranted for LEEs, including small entity LEEs, we believe that flexible and achievable pollution control requirements are promoted through alternative standards, alternative compliance options, and emissions averaging as a means of demonstrating compliance with the standards for existing EGUs.

Comment: One commenter believes that the EPA should develop more limited monitoring requirements for small EGUs. The commenter notes small entities do not possess the monetary resources, manpower, or technical expertise needed to operate cutting-edge monitoring techniques such as Hg CEMS and PM CEMS. The commenter notes the EPA could have identified monitoring alternatives to the SER panel for consideration.

Response: The EPA provided monitoring alternatives to using PM CEMS, HCl CEMS, and Hg CEMS in its proposed standards and in this final rule. The continuous compliance alternatives are available to all affected sources, including small entities. As alternatives to the use of PM CEMS and HCl CEMS, sources are allowed to conduct additional performance testing. Sorbent trap monitoring is allowed in lieu of Hg CEMS.

Comment: Several commenters believe the EPA has not sufficiently complied with the requirements of the RFA or adequately considered the impact this rulemaking would have on small entities. One commenter believes the EPA has not engaged in meaningful outreach and consultation with small entities and therefore recommends that the EPA seek to revise the court-ordered deadlines to which this rulemaking is subject, re-convene the SBAR panel, prepare a new initial regulatory flexibility analysis

(IRFA), and issue it for additional public comment prior to final rulemaking. The commenter believes the IRFA does not sufficiently consider impacts on small entities as identified in the SBAR Panel Report. The commenter believes it is not apparent that the EPA considered the recommendations of the Panel. The commenter believes the description of significant alternatives in the IRFA is almost entirely quoted from the SBAR Panel Report, which the commenter does not believe is an adequate substitute for the EPA's own analysis of alternatives. The commenter also notes the EPA does not discuss the potential impacts of its decisions on small entities or the impacts of possible flexibilities. Where the EPA does consider regulatory alternatives in principle, the commenter believes it does not provide sufficient support for its decisions to understand on what basis the EPA rejected alternatives that may or may not have reduced burden on small entities while meeting the stated objectives of the rule. Additionally, the commenter notes that the EPA did not evaluate the economic or environmental impacts of significant alternatives to the proposed rule. One commenter believes that the EPA's stated reasons for declining to specify or analyze an area source standard are inadequate under the RFA. The commenter believes the EPA must give serious consideration to regulatory alternatives that accomplish the stated objectives of the CAA while minimizing any significant economic impacts on small entities and that the EPA has a duty to specify and analyze this option or to more clearly state its policy reasons for excluding serious consideration of a separate standard for area sources. A commenter believes the EPA did not fully consider the subcategorization of sources such as boilers designed to burn lignite coals versus other fossil fuels,

especially in regard to non-mercury metal and acid gas emissions. The commenter references the SBAR Panel Report suggestion provided in the preamble of the proposed rule that the EPA consider developing an area source vs. major source distinction for the source category and the EPA's response. Another commenter is concerned that the recommendations made by the SER participants were ignored and not discussed in the rulemaking. Specifically, the commenter notes the EPA did not discuss subcategorizing by age, type of plant, fuel, physical space constraints or useful anticipated life of the plant. Nor did the EPA establish GACT for smaller emitters to alleviate regulatory costs and operational difficulties. A commenter believes it is likely that different numerical or work practice standards are appropriate for area sources of HAP.

Response: The EPA disagrees with one commenter's assertion that the agency has not complied with the requirements of the RFA. The EPA complied with both the letter and spirit of the RFA, notwithstanding the constraints of the court-ordered deadline. For example, the EPA notified the Chief Counsel for Advocacy of the SBA of its intent to convene a Panel; compiled a list of SERs for the Panel to consult with; and convened the Panel. The Panel met with SERs to collect their advice and recommendations; reviewed the EPA materials; and drafted a report of Panel findings. The EPA further disagrees with the commenter's assertion that the EPA's IRFA does not sufficiently consider impacts on small entities. The EPA's IRFA, which is included in chapter 10 of the RIA for the proposed rule, addresses the statutorily required elements of an IRFA, such as the economic impact of the proposed rule on small entities and the Panel's findings.

The EPA disagrees with the comment that recommendations made by the SERs were not considered or discussed in the proposed rulemaking such as recommendations regarding subcategorization and separate GACT standards for area sources. The preamble to the proposed standards includes a detailed discussion of how the EPA determined which subcategories and sources would be regulated *(76 FR 25036-25037;* May 3, 2011). In that discussion, the EPA explains the rationale for its proposed subcategories based on five unit design types. In addition, the EPA acknowledges the subcategorization suggestions from the SERs and explains its reasons for not subcategorizing on those bases. The preamble to the proposed standards also includes a discussion of the SERs' suggestion that area source EGUs be distinguished from major-source EGUs and the EPA's reasons for not making that distinction *(76 FR 25020-25021;* May 3, 2011).

The EPA also disagrees with the suggestion that the Agency pursue an extension of the timeline for final rulemaking such that the SBAR Panel can be reconvened and a new IRFA can be prepared and released for public comment prior to the final rulemaking. The EPA entered into a Consent Decree to resolve litigation alleging that the EPA failed to perform a non-discretionary duty to promulgate CAA section 112(d) standards for EGUs. *See American Nurses Ass'n* v. *EPA,* 08-2198 (D.D.C.). That Decree required the EPA to sign the final MATS rule by November 16, 2011, unless the agency sought to extend the deadline consistent with the requirements of the modification provision of the Consent Decree. The EPA and Plaintiffs stipulated to a 30-day extension consistent with the modification provisions of the Consent Decree and the rule must be signed no later than December 16, 2011. If plaintiffs in the

American Nurses litigation objected to an additional extension request, which we believe would have been likely, the Agency would have had to file a motion with the Court seeking an extension of the deadline. Consistent with governing case law, the Agency would have been required to demonstrate in its motion for extension that it was impossible to finalize the rule by the deadline provided in the Consent Decree. *See Sierra Club* v. *Jackson,* Civil Action No. 01-1537 (D.D.C.) (Opinion of the Court denying EPA's motion to extend a consent decree deadline). The EPA negotiated a 30-day extension and was able to complete the rule by December 16, 2011; accordingly, the Agency had no basis for seeking a further extension of time.

A detailed description of the changes made to the rule since proposal, including those made as a result of feedback received during the public comment process can be found in sections VI (NESHAP) and X (NSPS) of this preamble. Changes explained in the identified sections include those related to applicability; subcategorization; work practices; periods of startup, shutdown, and malfunction; initial testing and compliance; continuous compliance; and notification, recordkeeping, and reporting.

4. Description and Estimate of the Affected Small Entities

For the purposes of assessing the impacts of MATS on small entities, a small entity is defined as:

(1) A small business according to the Small Business Administration size standards by the North American Industry Classification System (NAICS) category of the owning entity. The range of small

business size standards for electric utilities is 4 billion kilowatt hours (kWh) of production or less;

(2) A small government jurisdiction that is a government of a city, county, town, district, or special district with a population of less than 50,000; and

(3) A small organization that is any not for profit enterprise that is independently owned and operated and is not dominant in its field.

The EPA examined the potential economic impacts to small entities associated with this rulemaking based on assumptions of how the affected entities will install control technologies in compliance with MATS. This analysis does not examine potential indirect economic impacts associated with this rule, such as employment effects in industries providing fuel and pollution control equipment, or the potential effects of electricity price increases on industries and households.

The EPA used Velocity Suite's Ventyx data as a basis for identifying plant ownership and compiling the list of potentially affected small entities. The Ventyx dataset contains detailed ownership and corporate affiliation information. The analysis focused only on those EGUs affected by the rule, which includes units burning coal, oil, petroleum coke, or coal refuse as the primary fuel, and excludes any combustion turbine units or EGUs burning natural gas. Also, because the rule does not affect combustion units with an equivalent electricity generating capacity up to 25 MW, small entities that do not own at least one combustion unit with a capacity greater than 25 MW were removed from the dataset. For the affected units remaining, boiler and generator capacity, heat input, generation, and emissions data

were aggregated by owner and then by parent company. Entities with more than 4 billion kWh of annual electricity generation were removed from the list, as were municipal owned entities with a population greater than 50,000. For cooperatives, investor owned utilities, and subdivisions that generate less than 4 billion kWh of electricity annually but which may be part of a large entity, additional research on power sales, operating revenues, and other business activities was performed to make a final determination regarding size. Finally, small entities for which the IPM does not project generation in 2015 in the base case were omitted from the analysis because they are not projected to be operating and, thus, are not projected to face the costs of compliance with the rule. After omitting entities for the reasons above, the EPA identified a total of 82 potentially affected small entities that are affiliated with 102 EGUs.

5. Compliance Cost Impacts

The number of potentially affected small entities by ownership type and potential impacts of MATS are presented in Chapter 7 of the RIA and summarized here. The EPA estimated the annualized net compliance cost to small entities to be approximately $ 106 million in 2015 (2007].

The EPA assessed the economic and financial impacts of the final rule using the ratio of compliance costs to the value of revenues from electricity generation, and our results focus on those entities for which this measure could be greater than 1 percent or 3 percent. Of the 82 small entities identified, The EPA's analysis shows 40 entities may experience compliance costs greater than 1 percent of base generation revenues in 2015, and 35 may experience

compliance costs greater than 3 percent of base revenues. Also, all generating capacity at 3 small entities is projected to be uneconomic to maintain. In this analysis, the cost of withdrawing a unit as uneconomic is estimated as the base case profit that is forgone by not operating under the policy case. Because 35 of the 82 total units, or more than 40 percent, are estimated to incur compliance cost greater than 3 percent of base revenues, the EPA has concluded that it cannot certify that there will be no significant economic impact on a substantial number of small entities (SISNOSE) for this rule. Results for small entities discussed here do not account for the reality that electricity markets are regulated in parts of the country. Entities operating in regulated or cost-of-service markets should be able to recover all of their costs of compliance through rate adjustments.

Note that the estimated costs for small entities are significantly lower than those estimated by the EPA for the MATS proposal (which were $ 379 million). This is driven by a small group of units (less than 6 percent) which were projected to be uneconomic to operate under the proposal (and hence incurred lost profits due to lost electricity revenues), but are now projected to continue their operations under MATS. In addition, the EPA's modeling indicates one unit that would have operated at a low capacity factor under the base case would find it economical to increase its generation significantly under MATS to meet electricity demand in its region. Excluding this unit, the total cost impacts across all entities would be roughly $ 175 million. Changes in compliance behavior for this small group of units, in particular the one unit which operates at a higher capacity factor, has a substantial impact on total costs as their increased

generation revenues offsets a large portion of the compliance costs.

The most significant components of incremental costs to these entities are changes in electricity revenues, followed by the increased capital and operating costs for retrofits. Capital and operating costs increase across all ownership types, but the direction of changes in electricity revenues varies among ownership types. All ownership types, with the exception of private entities, experience a net gain in electricity revenues under the MATS, unlike projections from the EPA's modeling during the proposal, where only municipals benefitted from higher electricity revenues. The change in electricity revenue takes into account both the profit lost from units that do not operate under the policy case and the difference in revenue for operating units under the policy case. According to the EPA's modeling, an estimated 274 MW of capacity owned by small entities are considered uneconomic to operate under the policy case, resulting in a net loss of $ 13 million (in 2007] in profits. On the other hand, many operating units actually increase their electricity revenue due to higher electricity prices under MATS. In addition, as mentioned above, the EPA's modeling indicates one unit finds it economical to increase its capacity factor significantly under the policy case which results in significantly higher revenues offsetting the costs.

6. Description of Steps To Minimize Impacts on Small Entities

Consistent with the requirements of the RFA and SBREFA, the EPA has taken steps to minimize the significant economic impact on small entities. Because this rule does not affect units with a generating capacity of less than 25 MW, small entities that do not

own at least one generating unit with a capacity greater than 25 MW are not subject to the rule. According to the EPA's analysis, among the coal- and oil-fired EGUs (*i.e.*, excluding combined cycle gas turbines and gas combustion turbines) about 26 potentially small entities only own EGUs with a capacity less than or equal to 25 MW, and none of those entities are subject to the final rule based on the statutory definition of potentially regulated units.

For units affected by the proposed rule, the EPA considered a number of comments received, both during the Small Business Advocacy Review (SBAR) Panel and the public comment period. While none of the alternatives adopted is specifically applied to small entities, the EPA believes these modifications will make compliance less onerous for all regulated units, including those owned by small entities.

a. Work practice standards. The EPA proposed numerical emission standards that would apply at all times, including during periods of startup and shutdown. After reviewing comments and other data regarding the nature of these periods of operation, the EPA is finalizing a work practice standard for periods of startup and shutdown. The EPA is also finalizing work practice standards for organic HAP from all subcategories of EGUs. Descriptions of the work practice requirements for startup and shutdown, as well as organic HAP and limited-use liquid oil-fired EGUs, can be found in section VI.D-E. of the preamble.

b. Continuous compliance and notification, record-keeping, and reporting. The final rule greatly simplifies the continuous compliance requirements and provides two basic approaches for most situations: use of continuous monitoring and periodic testing. The frequency of periodic testing has been decreased from

monthly in the proposal to quarterly in the final rule. In addition to simplifying compliance, the EPA believes these changes considerably reduce the overall burden associated with recordkeeping and reporting. These changes to the final rule are described in more detail in Section VI.G-H of this preamble.

c. Subcategorization. The Small Entity Representatives on the SBAR Panel were generally supportive of subcategorization and suggested a number of additional subcategories the EPA should consider when developing the final rule. Although it was not consistent with the statute to adopt the proposed subcategories, the EPA maintained the existing subcategories and split the "liquid oil-fired units" subcategory into three subcategories--continental, non-continental units, and limited-use units.

d. MACT floor calculations. As recommended by the EPA SBAR Panel representative, the EPA established the MACT floors using all the available ICR data that was received to the maximum extent possible consistent with the CAA requirements. The Agency believes this approach reasonably ensures that the emission limits selected as the MACT floors adequately represent the level of emissions actually achieved by the average of the units in the top 12 percent, considering operational variability of those units.

e. Alternatives not adopted. The EPA did not adopt several of the suggestions posed either during the SBAR Panel or public comment period. The EPA did not propose a percent reduction standard as an alternative to the concentration-based MACT floor. The percent reduction format for Hg and other HAP emissions would not have addressed the EPA's consideration of coal preparation practices that

remove Hg and other HAP before firing. Also, to account for the coal preparation practices, sources would be required to track the HAP concentrations in coal from the mine to the stack, and not just before and after the control device(s), and such an approach would be difficult to implement and enforce. Furthermore, the EPA does not believe the percent reduction standard is in line with the Court's interpretation of the CAA section 112 requirements. Even if we believed it was appropriate to establish a percent reduction standard, we do not have the data necessary to establish percent reduction standards for HAP, as explained further in the response to comments document.

The EPA determined not to establish GACT standards for area sources for a number of reasons. The data show that similar HAP emissions and control technologies are found on both major and area sources greater than 25 MW, and some large units are synthetic area sources. In fact, because of the significant number of well-controlled EGUs of all sizes, we believe it would be difficult to make a distinction between MACT and GACT. Moreover, the EPA believes the standards for area source EGUs should reflect MACT, rather than GACT, because there is no essential difference between area source and major source EGUs with respect to emissions of HAP

The EPA determined not to exercise its discretionary authority to establish health-based emission standards for HCl and other HAP acid gases. Given the limitations of the currently available information (*e.g.*, the HAP mix where EGUs are located, and the cumulative impacts of respiratory irritants from nearby sources), the environmental effects of HCl and

the other acid gas HAP, and the significant co-benefits from reductions in criteria pollutants the EPA determined that setting a conventional MACT standard for HCl and the other acid gas HAP was the appropriate course of action.

As required by SBREFA section 212, the EPA also is preparing a Small Entity Compliance Guide to help small entities comply with this rule. Small entities will be able to obtain a copy of the Small Entity Compliance guide at the following Web site: *http://www.epa.gov/airquality/powerplanttoxics/actions.html.*

D. Unfunded Mandates Reform Act of 1995

Title II of the UMRA of 1995, Public Law 104-4, establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. Under UMRA section 202, we generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to state, local, and tribal governments, in the aggregate, or to the private sector, of $ 100 million or more in any 1 year. Before promulgating a rule for which a written statement is needed, UMRA section 205 generally requires us to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of UMRA section 205 do not apply when they are inconsistent with applicable law. Moreover, UMRA section 205 allows us to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that

alternative was not adopted. Before we establish any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, we must develop a small government agency plan under UMRA section 203. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of regulatory proposals with significant federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We have determined that this rule contains a federal mandate that may result in expenditures of $ 100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Accordingly, we have prepared a written statement entitled "Unfunded Mandates Reform Act Analysis" under UMRA section 202 that is within the RIA and which is summarized below.

1. Statutory Authority

As discussed elsewhere in this preamble, the statutory authority for this rulemaking is CAA section 112. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. CAA section 112(b) lists the 188 chemicals, compounds, or groups of chemicals deemed by Congress to be HAP. These toxic air pollutants are to be regulated by NESHAP.

CAA section 112(d) directs us to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT-based standards. This NESHAP applies to all coal- and oil-fired EGUs.

In compliance with UMRA section 205(a), we identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives were presented in the RIA for the rulemaking.

The regulatory alternative upon which this rule is based represents the MACT floor for all regulated pollutants for all but one EGU subcategory for all but one regulated pollutant for that subcategory. These MACT floor-based standards represent the least costly and least burdensome alternative. Beyond-the-floor emission limits for Hg are for existing coal-fired EGUs in the subcategory for low rank virgin coal EGUs.

2. Social Costs and Benefits

The RIA prepared for this rule including the Agency's assessment of costs and benefits is in the docket.

It is estimated that HAP would be reduced by thousands of tons in 2015, relative to the base case, including reductions in HCl, HF, metallic HAP (including Hg), and several other organic HAP from EGUs. Studies have determined a relationship between exposure to certain of these HAP and the onset of cancer; however, the Agency is unable to provide a monetized estimate of the HAP benefits at this time. In addition, significant reductions in $PM_{2.5}$ and SO_2 will occur, including approximately 53 thousand tons of $PM_{2.5}$ and over 1 million tons of SO_2. These reductions will occur by 2016 and are expected to continue throughout the life of the affected sources. The major health effect associated with reducing $PM_{2.5}$ and $PM_{2.5}$ precursors (such as SO_2) is a reduction in premature mortality. Other health effects associated

with $PM_{2.5}$ emission reductions include avoiding cases of chronic bronchitis, heart attacks, asthma attacks, and work-lost days (*i.e.*, days when employees are unable to work). Although we are unable to monetize the benefits associated with the HAP emissions reductions other than for Hg or all benefits associated with Hg reductions, we are able to monetize the benefits associated with the $PM_{2.5}$ and SO_2 emissions reductions. For SO_2 and $PM_{2.5}$], we estimated the benefits associated with health effects of PM but were unable to quantify all categories of benefits (particularly those associated with ecosystem and visibility effects). Our estimates of the monetized benefits in 2016 associated with the implementation of the final rule range from $ 37 billion to $ 90 billion (2007 dollars) when using a 3 percent discount rate or from $ 33 billion to $ 81 billion (2007 dollars) when using a 7 percent discount rate). Our estimate of costs is $ 9.6 billion (2007 dollars). For more detailed information on the benefits and costs estimated for this rulemaking, refer to the RIA in the docket.

3. Future and Disproportionate Costs

The UMRA requires that we estimate, where accurate estimation is reasonably feasible, future compliance costs imposed by this rule and any disproportionate budgetary effects. Our estimates of the future compliance costs of this rule are discussed previously in this preamble.

The EPA assessed the economic and financial impacts of the rule on government-owned entities using the ratio of compliance costs to the value of revenues from electricity generation, and our results focus on those entities for which this measure could be greater than 1 percent or 3 percent of base revenues. The EPA projects that 42 government entities will

have compliance costs greater than 1 percent of base generation revenue in 2016, and 32 may experience compliance costs greater than 3 percent of base revenues. Overall, 6 units owned by government entities are expected to retire. The most significant components of incremental costs to these entities are the increased capital and operating costs, followed by changes in electricity revenues. For more details on these results and the methodology behind their estimation, see the results included in chapter 7 of the RIA.

4. Effects on the National Economy

The UMRA requires that we estimate the effect of this rule on the national economy. To the extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of the U.S. goods and services, if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material.

The nationwide economic impact of this rule is presented in the RIA in the docket. This analysis provides estimates of the effect of this rule on some of the categories mentioned above.

The results of the economic impact analysis are summarized previously in this preamble. The results show that, relative to baseline, there will be an average 3.1 percent increase in electricity price on average nationwide in 2016, with the range of increases from 1.3 percent to 6.3 percent in regions throughout the U.S., and a less than 1 percent increase in natural gas price nationwide in 2016. The roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the

absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[377] Power generation from coal-fired plants will fall by about 2 percent nationwide in 2016. No region of the U.S. is expected to experience a double-digit increase in retail electricity prices in 2015 or in any year later than that, according to the Agency's analysis, as a result of this rule. To put the electricity price effects in context, the roughly 3 percent incremental increase in aggregate end-user electricity prices projected to occur over the next 4 years is about the same as the 3 percent absolute average change in total end-user electricity prices observed on an annual basis.[378] Furthermore, the roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[379] Even with this rule in effect, electricity prices are projected to be lower in 2015 and 2020 than they were in 2010.[380]

5. Consultation With Government

The UMRA requires that we describe the extent of the Agency's prior consultation with affected state,

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[377] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 to 2010, Table 8-10.

[378] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 t0 2010, Table 8-10.

[379] Ibid.

[380] Ibid., EIA AEO 2010, Table-10 for price levels; and Chapterr 3 of the RIA for electricity price differential.

local, and tribal officials, summarize the officials' comments or concerns, and summarize our response to those comments or concerns. In addition, UMRA section 203 requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a regulatory action. Consistent with the intergovernmental consultation provisions of UMRA section 204, the EPA initiated consultations with governmental entities affected by this rule. The EPA invited the following 10 national organizations representing state and local elected officials to a meeting held on October 27, 2010, in Washington, DC: (1) National Governors Association; (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations of elected state and local officials have been identified by the EPA as the "Big 10" organizations appropriate to contact for purpose of consultation with elected officials. The purposes of the consultation were to provide general background on the rule, answer questions, and solicit input from state/local governments. During the meeting, officials asked clarifying questions regarding CAA section 112 requirements and central decision points presented by the EPA (*e.g.*, use of surrogate pollutants to address HAP, subcategorization of source category, assessment of emissions variability). They also expressed uncertainty with regard to how utility boilers owned/operated by state and local entities would be impacted, as well as with regard to the potential burden associated with implementing the rule on state

and local entities (*i.e.*, burden to re-permit affected EGUs or update existing permits). Officials requested, and the EPA provided, addresses associated with the 112 state and local governments estimated to be potentially impacted by the rule. The EPA has not received additional questions or requests from state or local officials.

Consistent with UMRA section 205, the EPA has identified and considered a reasonable number of regulatory alternatives. Because the potential existed for a significant impact for substantial number of small entities, the EPA convened a SBAR Panel to obtain advice and recommendation of representatives of the small entities that potentially would be subject to the requirements of the rule. As part of that process, the EPA considered several options, which are discussed previously in this preamble. Those options included establishing emission limits, establishing work practice standards, establishing subcategories, and consideration of monitoring options. The regulatory alternative selected is a combination of the options considered and includes provisions regarding a number of the recommendations resulting from the SBAR Panel process as described below (see the Regulatory Flexibility Act discussion in this section of the preamble for more detail).

E. Executive Order 13132, Federalism

Under EO 13132, the EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by state and local governments, or the EPA consults with state and local

officials early in the process of developing the final action.

The EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs. Accordingly, the EPA provides the following federalism summary impact statement as required by section 6(b) of EO 13132.

Based on estimates in the RIA, provided in the docket, the final rule may have federalism implications because the rule may impose approximately $ 294 million in annual direct compliance costs on an estimated 96 state or local governments. Specifically, we estimate that there are 80 municipalities, 5 states, and 11 political subdivisions (*i.e.,* a public district with territorial boundaries embracing an area wider than a single municipality and frequently covering more than one county for the purpose of generating, transmitting and distributing electric energy) that may be directly impacted by this final rule. Responses to the EPA's 2010 ICR were used to estimate the nationwide number of potentially impacted state or local governments. As previously explained, this 2010 survey was submitted to all coal- and oil-fired EGUs listed in the 2007 version of DOE/EIA's "Annual Electric Generator Report," and "Power Plant Operations Report."

The EPA consulted with state and local officials in the process of developing the rule to permit them to have meaningful and timely input into its development. The EPA met with 10 national organizations representing state and local elected officials to provide general background on the rule, answer questions, and solicit input. In the final rule, EPA has

provided flexibilities that will lower compliance costs for these entities. The EPA also recognizes that municipalities may need a longer compliance time-frame because of required approval processes.

F. Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

Subject to EO 13175 *(65 FR 67249;* November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement. Executive Order 13175 requires the EPA to develop an accountable process to ensure "meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications."

The EPA has concluded that this action may have tribal implications. The EPA offered consultation with tribal officials early in the regulation development process to permit them an opportunity to have meaningful and timely input. Consultation letters were sent to 584 tribal leaders and provided information regarding the EPA's development of this rule and offered consultation. At the request of the tribes, three consultation meetings were held: December 7, 2010, with the Upper Sioux Community of Minnesota; December 13, 2010, with Moapa Band of Paiutes, Forest County Potawatomi, Standing Rock Sioux Tribal Council, and Fond du Lac Band of Chippewa; January 5, 2011, with the Forest County Potawatomi, and a representative from the National Tribal Air Association (NTAA). In these meetings, the

EPA presented the authority under the CAA used to develop these rules and an overview of the industry and the industrial processes that have the potential for regulation. Tribes expressed concerns about the impact of EGUs in Indian country. Specifically, they were concerned about potential Hg deposition and the impact on the water resources of the tribes, with particular concern about the impact on subsistence lifestyles for fishing communities, the cultural impact of impaired water quality for ceremonial purposes, and the economic impact on tourism. In light of these concerns, the tribes expressed interest in an expedited implementation of the rule. Other concerns expressed by tribes related to how the Agency would consider variability in setting the standards, and the use of tribal-specific fish consumption data from the tribes in our assessments. They were not supportive of using work practice standards as part of the rule, and asked the Agency to consider going beyond the MACT floor to offer more protection for the tribal communities.

In addition to these consultations, the EPA also conducted outreach on this rule through presentations at the National Tribal Forum in Milwaukee, WI; phone calls with the NTAA; and a webinar for tribes on the proposed rule. The EPA specifically requested tribal data that could support the appropriate and necessary analyses and the RIA for this rule. In addition, the EPA held individual consultations with the Navajo Nation on October 12, 2011; as well as the Gila River Indian Community, Ak-Chin Indian Community, and the Hopi Nation on October 14, 2011. These tribes expressed concerns about the impact of the rule on the Navajo Generating Station (NGS), the impact on the cost of the water allotted to the tribes from the Central Arizona Project (CAP), the impact on tribal revenues from the coal mining operations (*i.e.*,

assumptions about reduced mining if NGS were to retire one or more units), and the impacts on employment of tribal members at both the NGS and the mine. More specific comments can be found in the docket.

The EPA will continue to work with these and other potentially affected tribes as this final rule is implemented.

G. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks

This final rule is subject to EO 13045 *(62 FR 19885;* April 23, 1997) because it is an economically significant regulatory action as defined by EO 12866, and EPA believes that the environmental health or safety risk addressed by this action may have a disproportionate effect on children. Accordingly, we have evaluated the environmental health or safety effects of the standards on children.

Although this final rule is based on technology performance, the standards are designed to protect against hazards to public health with an adequate margin of safety as described in Section III of this preamble. The protection offered by this rule is particularly important for children, especially the developing fetus. As referenced in Chapter 4 of the RIA, "Mercury and Other HAP Benefits Analysis," children are more vulnerable than adults to many HAP emitted by EGUs due to differential behavior patterns and physiology. These unique susceptibilities were carefully considered in a number of different ways in the analyses associated with this rulemaking, and are summarized in the RIA. We also estimate substantial health improvements for children in the

form of 130,000 fewer asthma attacks, 3,100 fewer emergency room visits due to asthma, 6,300 fewer cases of acute bronchitis, and approximately 140,000 fewer cases of upper and lower respiratory illness.

H. Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 *(66 FR 28355;* May 22, 2001) requires EPA to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and Regulatory Affairs, OMB, for actions identified as "significant energy actions." This action, which is a significant regulatory action under EO 12866, is likely to have a significant adverse effect on the supply, distribution, or use of energy. We have prepared a Statement of Energy Effects for this action as follows.

We estimate a 3.1 percent price increase for electricity nationwide in 2016 and a less than 2 percent percentage fall in coal-fired power production as a result of this rule. The EPA projects that electric power sector-delivered natural gas prices will increase by about 0.6 percent over the 2015 to 2030 timeframe. For more information on the estimated energy effects, please refer to the economic impact analysis for this final rule. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104-113; *15 U.S.C. 272* note) directs the EPA to use voluntary consensus standards in its regulatory

activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves technical standards. The EPA cites the following standards in the final rule: EPA Methods 1, 2, 2A, 2C, 2F, 2G, 3A, 3B, 4, 5, 5D, 17, 19, 23, 26, 26A, 29, 30B of 40 CFR part 60 and Method 320 of 40 CFR part 63. Consistent with the NTTAA, the EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods. No applicable voluntary consensus standards were identified for EPA Methods 2F, 2G, 5D, and 19. The search and review results have been documented and are placed in the docket for the proposed rule.

The three voluntary consensus standards described below were identified as acceptable alternatives to EPA test methods for the purposes of the final rule.

The voluntary consensus standard American National Standards Institute (ANSI)/American Society of Mechanical Engineers (ASME) PTC 19-10-1981, "Flue and Exhaust Gas Analyses [part 10, Instruments and Apparatus]" is cited in the final rule for its manual method for measuring the O_2, CO_2, and CO content of exhaust gas. This part of ANSI/ASME PTC 19-10-1981 is an acceptable alternative to Method 3B.

The voluntary consensus standard ASTM D6348-03 (Reapproved 2010), "Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform (FTIR) Spectroscopy" is acceptable as an alternative to Method 320 and is cited in the final rule, but with several conditions: (1) The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory; and (2) In ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (Equation A5.5). In order for the test data to be acceptable for a compound, %R must be 70% >/= R </= 130%. If the %R value does not meet this criterion for a target compound, the test data are not acceptable for that compound and the test must be repeated for that analyte (*i.e.*, the sampling and/or analytical procedure should be adjusted before a retest). The %R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated %R value for that compound by using the following equation: *Reported Result = (Measured Concentration in the Stack x 100)/% R.*

The voluntary consensus standard ASTM D6784-02, "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)," is an acceptable alternative to use of EPA Method 29 for Hg only or Method 30B for the purpose of conducting relative accuracy tests of Hg continuous monitoring systems under this final rule. Because of the limitations of this method in terms of total sampling volume, it is not appropriate for use in performance testing under this rule. In addition to the voluntary consensus standards the EPA used in

the final rule, the search for emissions measurement procedures identified 16 other voluntary consensus standards. The EPA determined that 14 of these 16 standards identified for measuring emissions of the HAP or other pollutants subject to emission standards in the final rule were impractical alternatives to EPA test methods for the purposes of this final rule. Therefore, the EPA did not adopt these standards for this purpose. The reasons for this determination for the 14 methods are discussed below, and the remaining 2 methods are discussed later in this section.

The voluntary consensus standard ASTM D3154-00, "Standard Method for Average Velocity in a Duct (Pitot Tube Method)," is impractical as an alternative to EPA Methods 1, 2, 3B, and 4 for the purposes of this rulemaking because the standard appears to lack in quality control and quality assurance requirements. Specifically, ASTM D3154-00 does not include the following: (1) proof that openings of standard pitot tube have not plugged during the test; (2) if differential pressure gauges other than inclined manometers (*e.g.*, magnehelic gauges) are used, their calibration must be checked after each test series; and (3) the frequency and validity range for calibration of the temperature sensors.

The voluntary consensus standard ASTM D3464-96 (Reapproved 2001), "Standard Test Method Average Velocity in a Duct Using a Thermal Anemometer," is impractical as an alternative to EPA Method 2 for the purposes of this rule primarily because applicability specifications are not clearly defined, *e.g.*, range of gas composition, temperature limits. Also, the lack of supporting quality assurance data for the calibration procedures and specifications, and certain variability

issues that are not adequately addressed by the standard limit the EPA's ability to make a definitive comparison of the method in these areas.

The voluntary consensus standard ISO 10780:1994, "Stationary Source Emissions--Measurement of Velocity and Volume Flowrate of Gas Streams in Ducts," is impractical as an alternative to EPA Method 2 in this rule. The standard recommends the use of an L-shaped pitot, which historically has not been recommended by the EPA. The EPA specifies the S-type design which has large openings that are less likely to plug up with dust.

The voluntary consensus standard, CAN/CSA Z223.2-M86 (1999), "Method for the Continuous Measurement of Oxygen, Carbon Dioxide, Carbon Monoxide, Sulphur Dioxide, and Oxides of Nitrogen in Enclosed Combustion Flue Gas Streams," is unacceptable as a substitute for EPA Method 3A because it does not include quantitative specifications for measurement system performance, most notably the calibration procedures and instrument performance characteristics. The instrument performance characteristics that are provided are non-mandatory and also do not provide the same level of quality assurance as the EPA methods. For example, the zero and span/calibration drift is only checked weekly, whereas the EPA methods require drift checks after each run.

Two very similar voluntary consensus standards, ASTM D5835-95 (Reapproved 2001), "Standard Practice for Sampling Stationary Source Emissions for Automated Determination of Gas Concentration," and ISO 10396:1993, "Stationary Source Emissions: Sampling for the Automated Determination of Gas Concentrations," are impractical alternatives to EPA

Method 3A for the purposes of this final rule because they lack in detail and quality assurance/quality control requirements. Specifically, these two standards do not include the following: (1) Sensitivity of the method; (2) acceptable levels of analyzer calibration error; (3) acceptable levels of sampling system bias; (4) zero drift and calibration drift limits, time span, and required testing frequency; (5) a method to test the interference response of the analyzer; (6) procedures to determine the minimum sampling time per run and minimum measurement time; and (7) specifications for data recorders, in terms of resolution (all types) and recording intervals (digital and analog recorders, only).

The voluntary consensus standard ISO 12039:2001, "Stationary Source Emissions--Determination of Carbon Monoxide, Carbon Dioxide, and Oxygen--Automated Methods," is not acceptable as an alternative to EPA Method 3A. This ISO standard is similar to EPA Method 3A, but is missing some key features. In terms of sampling, the hardware required by ISO 12039:2001 does not include a 3-way calibration valve assembly or equivalent to block the sample gas flow while calibration gases are introduced. In its calibration procedures, ISO 12039:2001 only specifies a two-point calibration while EPA Method 3A specifies a three-point calibration. Also, ISO 12039:2001 does not specify performance criteria for calibration error, calibration drift, or sampling system bias tests as in the EPA method, although checks of these quality control features are required by the ISO standard.

The voluntary consensus standard ASTM D6522-00, "Standard Test Method for the Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired

Reciprocating Engines, Combustion Turbines, Boilers and Process Heaters Using Portable Analyzers" is not an acceptable alternative to EPA Method 3A for measuring CO and O_2 concentrations for this final rule as the method is designed for application to sources firing natural gas.

The voluntary consensus standard ASME PTC-38-80 R85 (1985), "Determination of the Concentration of Particulate Matter in Gas Streams," is not acceptable as an alternative for EPA Method 5 because ASTM PTC-38-80 is not specific about equipment requirements, and instead presents the options available and the pros and cons of each option. The key specific differences between ASME PTC-38-80 and the EPA methods are that the ASME standard: (1) Allows in-stack filter placement as compared to the out-of-stack filter placement in EPA Methods 5 and 17; (2) allows many different types of nozzles, pitots, and filtering equipment; (3) does not specify a filter weighing protocol or a minimum allowable filter weight fluctuation as in the EPA methods; and (4) allows filter paper to be only 99 percent efficient, as compared to the 99.95 percent efficiency required by the EPA methods.

The voluntary consensus standard ASTM D3685/D3685M-98, "Test Methods for Sampling and Determination of Particulate Matter in Stack Gases," is similar to EPA Methods 5 and 17, but is lacking in the following areas that are needed to produce quality, representative particulate data: (1) Requirement that the filter holder temperature should be between 120 [degrees] C and 134 [degrees] C, and not just "above the acid dew-point"; (2) detailed specifications for measuring and monitoring the filter holder temperature during sampling; (3) procedures similar to EPA Methods 1, 2, 3, and 4, that are required by

EPA Method 5; (4) technical guidance for performing the Method 5 sampling procedures, *e.g.*, maintaining and monitoring sampling train operating temperatures, specific leak check guidelines and procedures, and use of reagent blanks for determining and subtracting background contamination; and (5) detailed equipment and/or operational requirements, *e.g.*, component exchange leak checks, use of glass cyclones for heavy particulate loading and/or water droplets, operating under a negative stack pressure, exchanging particulate loaded filters, sampling preparation and implementation guidance, sample recovery guidance, data reduction guidance, and particulate sample calculations input.

The voluntary consensus standard ISO 9096:1992, "Determination of Concentration and Mass Flow Rate of Particulate Matter in Gas Carrying Ducts--Manual Gravimetric Method," is not acceptable as an alternative for EPA Method 5. Although sections of ISO 9096 incorporate EPA Methods 1, 2, and 5 to some degree, this ISO standard is not equivalent to EPA Method 5 for collection of PM. The standard ISO 9096 does not provide applicable technical guidance for performing many of the integral procedures specified in Methods 1, 2, and 5. Major performance and operational details are lacking or nonexistent, and detailed quality assurance/quality control guidance for the sampling operations required to produce quality, representative particulate data (*e.g.*, guidance for maintaining and monitoring train operating temperatures, specific leak check guidelines and procedures, and sample preparation and recovery procedures) are not provided by the standard, as in EPA Method 5. Also, details of equipment and/or operational requirements, such as those specified in EPA Method 5, are not included in the ISO standard, *e.g.*, stack gas

moisture measurements, data reduction guidance, and particulate sample calculations.

The voluntary consensus standard CAN/CSA Z223.1-M1977, "Method for the Determination of Particulate Mass Flows in Enclosed Gas Streams," is not acceptable as an alternative for EPA Method 5. Detailed technical procedures and quality control measures that are required in EPA Methods 1, 2, 3, and 4 are not included in CAN/CSA Z223.1. Second, CAN/CSA Z223.1 does not include the EPA Method 5 filter weighing requirement to repeat weighing every 6 hours until a constant weight is achieved. Third, EPA Method 5 requires the filter weight to be reported to the nearest 0.1 milligram (mg), while CAN/CSA Z223.1 requires reporting only to the nearest 0.5 mg. Also, CAN/CSA Z223.1 allows the use of a standard pitot for velocity measurement when plugging of the tube opening is not expected to be a problem. The EPA Method 5 requires an S-shaped pitot.

The voluntary consensus standard EN 1911-1,2,3 (1998), "Stationary Source Emissions-Manual Method of Determination of HCl-Part 1: Sampling of Gases Ratified European Text-Part 2: Gaseous Compounds Absorption Ratified European Text-Part 3: Adsorption Solutions Analysis and Calculation Ratified European Text," is impractical as an alternative to EPA Methods 26 and 26A. Part 3 of this standard cannot be considered equivalent to EPA Method 26 or 26A because the sample absorbing solution (water) would be expected to capture both HCl and chlorine gas, if present, without the ability to distinguish between the two. The EPA Methods 26 and 26A use an acidified absorbing solution to first separate HCl and chlorine gas so that they can be selectively absorbed, analyzed, and reported separately. In addition, in EN 1911 the

absorption efficiency for chlorine gas would be expected to vary as the pH of the water changed during sampling.

The voluntary consensus standard EN 13211 (1998), is not acceptable as an alternative to the Hg portion of EPA Method 29 primarily because it is not validated for use with impingers, as in the EPA method, although the method describes procedures for the use of impingers. This European standard is validated for the use of fritted bubblers only and requires the use of a side (split) stream arrangement for isokinetic sampling because of the low sampling rate of the bubblers (up to 3 liters per minute, maximum). Also, only two bubblers (or impingers) are required by EN 13211, whereas EPA Method 29 require the use of six impingers. In addition, EN 13211 does not include many of the quality control procedures of EPA Method 29, especially for the use and calibration of temperature sensors and controllers, sampling train assembly and disassembly, and filter weighing.

Two of the 16 voluntary consensus standards identified in this search were not available at the time the review was conducted for the purposes of the final rule because they are under development by a voluntary consensus body: ASME/BSR MFC 13M, "Flow Measurement by Velocity Traverse," for EPA Method 2 (and possibly 1); and ASME/BSR MFC 12M, "Flow in Closed Conduits Using Multiport Averaging Pitot Primary Flowmeters," for EPA Method 2.

Finally, in addition to the three voluntary consensus standards identified as acceptable alternatives to EPA methods required in the final rule, the EPA is also specifying four voluntary consensus standards in the rule for use in sampling and analysis of liquid oil samples for moisture content. These standards are:

ASTM D95-05 (Reapproved 2010), "Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation," ASTM D4006-11, "Standard Test Method for Water in Crude Oil by Distillation," ASTM D4177-95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," and ASTM D4057-06 (Reapproved 2011), "Standard Practice for Manual Sampling of Petroleum and Petroleum Products."

Table 5, section 4.1.1.5 of appendix A, and section 3.1.2 of appendix B to subpart UUUUU, 40 CFR part 63, list the EPA testing methods included in the final rule. Under section 63.7(f) and section 63.8(f) of subpart A of the General Provisions, a source may apply to the EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of the EPA testing methods, performance specifications, or procedures specified.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 *(59 FR 7629;* February 16, 1994) establishes federal executive policy on environmental justice (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S.

The EPA has determined that this final rule will not have disproportionately high and adverse human

health or environmental effects on minority, low income, and indigenous populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority, low income, and indigenous populations.

This final rule establishes national emission standards for new and existing EGUs that combust coal and oil. The EPA estimates that there are approximately 1,400 units located at 600 facilities covered by this final rule.

This final rule will reduce emissions of all the listed HAP that come from EGUs. This includes metals (Hg, As, Be, Cd, Cr, Pb, Mn, Ni, and Se), organics (POM, acetaldehyde, acrolein, benzene, dioxins, ethylene dichloride, formaldehyde, and PCB), and acid gases (HCl and HF). At sufficient levels of exposure, these pollutants can cause a range of health effects including cancer; irritation of the lungs, skin, and mucous membranes; effects on the central nervous system such as memory and IQ loss and learning disabilities; damage to the kidneys; and other acute health disorders.

The final rule will also result in substantial reductions of criteria pollutants such as CO, PM, and SO_2. Sulfur dioxide is a precursor pollutant that is often transformed into fine PM ($PM_{2.5}$) in the atmosphere. Reducing direct emissions of $PM_{2.5}$ and SO_2 will, as a result, reduce concentrations of $PM_{2.5}$ in the atmosphere. These reductions in $PM_{2.5}$ will provide large health benefits, such as reducing the risk of premature mortality for adults, chronic and acute bronchitis, childhood asthma attacks, and hospitalizations for other respiratory and cardiovascular diseases. (For

more details on the health effects of metals, organics, and $PM_{2.5}$, please refer to the RIA contained in the docket for this rulemaking.) This final rule will also have a small effect on electricity and natural gas prices but has the potential to affect the cost structure of the utility industry and could lead to shifts in how and where electricity is generated.

This final rule is one of a group of regulatory actions that the EPA has taken and will take over the next several years to respond to statutory and judicial mandates that will reduce exposure to HAP and $PM_{2.5}$, as well as to other pollutants, from EGUs and other sources. In addition, the EPA will pursue energy efficiency improvements throughout the economy, along with other federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements. Together, these rules and actions will have substantial and long-term effects on both the U.S. power industry and on communities currently breathing dirty air. Therefore, we anticipate significant interest in many, if not most, of these actions from EJ communities, among many others.

1. Key EJ Aspects of the Rule

This is an air toxics rule; therefore, it does not permit emissions trading among sources. Instead, this final rule will place a limit on the rates of Hg and other HAP emitted from each affected EGU. As a result, emissions of Hg and other HAP such as HCl will be substantially reduced in the vast majority of states. In some states, however, there may be small increases in Hg and other HAP emissions due to shifts in electricity generation from EGUs with higher emission rates to EGUs with already low emission rates. Hydrogen

chloride emissions are projected to increase at a small number of sources but that does not lead to any increased emissions at the state level.

The primary risk analysis to support the finding that this final rule is both appropriate and necessary includes an analysis of the effects of Hg from EGUs on people who rely on freshwater fish they catch as a regular and frequent part of their diet. These groups are characterized as subsistence level fishing populations or fishers. A significant portion of the data in this analysis came from published studies of EJ communities where people frequently consume locally-caught freshwater fish. These communities included: (1) White and black populations (including female and poor strata) surveyed in South Carolina; (2) Hispanic, Vietnamese and Laotian populations surveyed in California; and (3) Great Lakes tribal populations (Chippewa and Ojibwe) active on ceded territories around the Great Lakes. These data were used to help estimate risks to similar populations beyond the areas where the study data were collected. For example, while the Vietnamese and Laotian survey data were collected in California, given the ethnic (heritage) nature of these high fish consumption rates, we assumed that they could also be associated with members of these ethnic groups living elsewhere in the U.S. Therefore, the high-end consumption rates referenced in the California study for these ethnic groups were used to model risk at watersheds elsewhere in the U.S. As a result of this approach, the specific fish consumption patterns of several different EJ groups are fundamental to the EPA's assessment of both the underlying risks that make this final rule appropriate and necessary, and of the analysis of the benefits of reducing exposure to Hg and the other HAP.

The EPA's full analysis of risks from consumption of Hg-contaminated fish is contained in the RIA for this rule. The effects of this final rule on the health risks from Hg and other HAP are presented in the preamble and in the RIA for this rule.

2. Potential Environmental and Public Health Impacts to 5Minority, Low Income, or Tribal Populations

The EPA has conducted several analyses that provide additional insight on the potential effects of this rule on EJ communities. These include: (1) The socio-economic distribution of people living close to affected EGUs who may be exposed to pollution from these sources; and (2) an analysis of the distribution of health effects expected from the reductions in $PM_{2.5}$ that will result from implementation of this final rule (co-benefits).

a. Socio-Economic Distribution. As part of the analysis for this final rule, the EPA reviewed the aggregate demographic makeup of the communities near EGUs covered by this final rule. Although this analysis gives some indication of populations that may be exposed to levels of pollution that cause concern, it does not identify the demographic characteristics of the most highly affected individuals or communities. Electric generating units usually have very tall emission stacks; this tends to disperse the pollutants emitted from these stacks fairly far from the source. In addition, several of the pollutants emitted by these sources, such as a common form of Hg and SO[2], are known to travel long distances and contribute to adverse impacts on both the environment and human health hundreds or even thousands of miles from where they were emitted (in the case of elemental Hg, globally).

The proximity-to-the-source review is included in the analysis for this final rule because some EGUs emit enough HAP such as Ni or Cr(VI) to cause elevated lifetime cancer risks greater than 1 in a million in nearby communities. In addition, the EPA's analysis indicates that there are localized areas with potential for elevated levels of Hg deposition around most U.S. EGUs.[381]

The analysis of demographic data used proximity-to-the-source as a surrogate for exposure to identify those populations considered to be living near affected sources, such that they have notable exposures to current HAP emissions from these sources. The demographic data for this analysis were extracted from the 2000 census data which were provided to the EPA by the U.S. Census Bureau. Distributions by race are based on demographic information at the census block level, and all other demographic groups are based on the extrapolation of census block group level data to the census block level. The socio-demographic parameters used in the analysis included the following categories: Racial (White, African American, Native American, Other or Multiracial, and All Other Races); Ethnicity (Hispanic); and Other (Number of people below the poverty line, Number of people with ages between 0 and 18, Number of people greater than or equal to 65, Number of people with no high school diploma).

In determining the aggregate demographic makeup of the communities near affected sources, the EPA focused on those census blocks within three miles of affected sources and determined the demographic composition (*e.g.*, race, income, etc.) of these census

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[381] See Excess Local Deposition TSD for more detail.

blocks and compared them to the corresponding compositions nationally. The radius of 3 miles (or approximately 5 kilometers) is consistent with other demographic analyses focused on areas around potential sources. In addition, air quality modeling experience has shown that the area within three miles of an individual source of emissions can generally be considered the area with the highest ambient air levels of the primary pollutants being emitted for most sources, both in absolute terms and relative to the contribution of other sources (assuming there are other sources in the area, as is typical in urban areas). Although facility processes and fugitive emissions may have more localized impacts, the EPA acknowledges that because of various stack heights there is the potential for dispersion beyond 3 miles. To the extent that any minority, low income, and indigenous subpopulation is disproportionately impacted by the current emissions as a result of the proximity of their homes to these sources, that subpopulation also stands to see increased environmental and health benefit from the emissions reductions called for by this rule. The results of the EPA's demographic analysis for affected sources are shown in the following table: n382 n383

Table 12--Comparative Summary of the Demographics Within 5 KM (3 Miles) of the Affected Sources

[Population in millions] fn382

	White	African American	Native American	Other and multi-racial	Hispanic	Minority fn383	Below poverty line
Near Source Total (3 mi)	8.78	2.51	0.10	2.52	2.86	5.13	2.43
% of Near Source Total	63	18	1	18	21	37	17
National Total	215	35	2.49	33.3	39.1	70.8	37.1
% of National Total	75	12	1	12	14	25	13

fn382 Racial and ethnic categories overlap and cannot be summed.

fn383 The "Minority" population is the overall population (in the first row) minus white population (in the second row).

The data indicate that coal-fired EGUs are located in areas where the minority share of the population living within a three mile buffer is higher than the national average by 12 percentage points or 48 percent. For these same areas, the percent of the population below the poverty line is also higher than

the national average by 4 percentage points or 31 percent. These results are presented in more detail in the "Review of Proximity Analysis," February 2011, a copy of which is available in the docket.

b. $PM_{2.5}$ (Co-Benefits) Analysis. As mentioned above, many of the steps EGUs will take to reduce their emissions of air toxics as required by this final rule will also reduce emissions of PM and SO_2. As a result, this final rule will reduce concentrations of $PM_{2.5}$ in the atmosphere. Exposure to $PM_{2.5}$ can cause or contribute to adverse health effects, such as asthma and heart disease, that significantly affect many minority, low-income, and tribal individuals and their communities. Fine PM ($PM_{2.5}$) is particularly (but not exclusively) harmful to children, the elderly, and people with existing heart and lung diseases, including asthma. Exposure can cause premature death and trigger heart attacks, asthma attacks in children and adults with asthma, chronic and acute bronchitis, and emergency room visits and hospitalizations, as well as milder illnesses that keep children home from school and adults home from work. Missing work due to illness or the illness of a child is a particular problem for people who have jobs that do not provide paid sick days. Low-wage employees also risk losing their jobs if they are absent too often, even if it is due to their own illness or the illness of a child or other relative. Finally, many individuals in these communities lack access to high quality health care to treat these types of illnesses. Due to all these factors, many minority and low-income communities are particularly susceptible to the health effects of $PM_{2.5}$ and receive a variety of benefits from reducing it.

We estimate that in 2016 the annual PM-related benefits of the final rule for adults include approximately 4,200 to 11,000 fewer premature mortalities, 2,900 fewer cases of chronic bronchitis, 4,800 fewer non-fatal heart attacks, 2,600 fewer hospitalizations (for respiratory and cardiovascular disease combined), 3.2 million fewer days of restricted activity due to respiratory illness and approximately 540,000 fewer lost work days. As described in EO 13045, Protection of Children from Environmental Health Risks and Safety Risks, we also estimate substantial health improvements for children.

We also examined the $PM_{2.5}$ mortality risks according to race, income, and educational attainment. We then estimated the change in $PM_{2.5}$ mortality risk as a result of this final rule among people living in the counties with the highest (top 5 percent) $PM_{2.5}$ mortality risk in 2005. We then compared the change in risk among the people living in these "high-risk" counties with people living in all other counties.

In 2005, people living in the highest risk counties and in the poorest counties had a substantially higher risk of $PM_{2.5}$ -related death than people living in the other 95 percent of counties. This was true regardless of race; the difference between the groups of counties for each race was large while the differences among races in both groups of counties was very small. In contrast, the analysis found that people with less than high school education had a significantly greater risk from $PM_{2.5}$ mortality than people with a greater than high school education. This was true both for the highest-risk counties and for the other counties. In summary, the analysis indicates that in 2005, educational status, living in one of the poorest

counties, and living in a high-risk county are associated with higher $PM_{2.5}$ mortality risk while race is not.

Our analysis demonstrates that this final rule will significantly reduce the $PM_{2.5}$ mortality among all populations of different races living throughout the U.S. compared to both 2005 and 2016 pre-rule (*i.e.*, base case) levels. The analysis indicates that people living in counties with the highest rates (top 5 percent) of $PM_{2.5}$ mortality risk in 2005 receive the largest reduction in mortality risk after this rule takes effect. We also find that people living in the poorest 5 percent of the counties receive a larger reduction in $PM_{2.5}$ mortality risk than all other counties. More information can be found in Section 7.11 of the RIA.

The EPA estimates that the benefits of the final rule are distributed among races, income levels, and levels of education fairly evenly. However, the analysis does indicate that this final rule in conjunction with the implementation of existing or final rules (*e.g.*, the CSAPR) will reduce the disparity in risk between those in the highest-risk counties and the other 95 percent of counties for all races and educational levels. In addition, in many cases implementation of this final rule and other rules will, together, reduce risks in the highest-risk counties to the approximate level of risk for the rest of the counties as it existed before implementation of the rule.

These results are presented in more detail in Section 7.11 of the RIA.

3. Meaningful Public Participation

The EPA defines "environmental justice" to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to

the development, implementation, and enforcement of environmental laws, regulations, and policies. To promote meaningful involvement, the EPA publicized the rulemaking via newsletters, EJ listserves, and the internet, including the Office of Policy's (OP) Rulemaking Gateway Web site (*http://yosemite.epa.gov/opei/RuleGate.nsf/*). During the comment period, the EPA discussed the proposed rule via a conference call with communities, conducted a community-oriented webinar on the proposed rule, and posted the webinar presentation on- line. The EPA also held three public hearings to receive additional input on the proposal.

There will continue to be opportunities for public notice and comment as the utilities move forward with implementation of this rule. Once the rule is finalized, affected EGUs will need to update their Title V operating permits to reflect their new emission limits, any other new applicable requirements, and the associated monitoring and recordkeeping from this rule. The Title V permitting process provides that when most permits are reopened (for example, to incorporate new applicable requirements) or renewed, there must be opportunity for public review and comments. In addition, after the public review process, the EPA has an opportunity to review the proposed permit and object to its issuance if it does not meet CAA requirements.

4. Additional Analysis

In addition to the previously described assessment of EJ impacts, the EPA conducted an analysis of sub-populations with particularly high potential risks of Hg exposure due to high rates of fish consumption. These populations overlap in many cases with traditional EJ populations and would benefit from Hg

reductions resulting from this rule. The EPA also conducted an analysis of the distribution of $PM_{2.5}$ related mortality risk according to the race, income and education of the population and how MATS changes this distribution. These analyses can be found in Section 7.12 of the RIA.

5. Summary

This final rule strictly limits the emissions rate of Hg and other HAP from every affected EGU. The EPA's analysis indicates substantial health benefits, including for minority, low income, and indigenous populations, from reductions in $PM_{2.5}$.

The EPA's analysis also indicates reductions in risks for individuals, including for members of minority populations, who eat fish frequently from U.S. lakes and rivers and who live near affected sources. Based on all the available information, the EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority, low income, and indigenous populations. The EPA is providing multiple opportunities for EJ communities to both learn about and comment on this rule and welcomes their participation as implementation of the rule proceeds.

K. Congressional Review Act

The Congressional Review Act, *5 U.S.C. 801* et seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the U.S. The EPA will submit a report containing this rule and

other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of the rule in the **Federal Register** A major rule cannot take effect until 60 days after it is published in the **Federal Register** This action is a "major rule" as defined by *5 U.S.C. 804(2)*. This rule will be effective April 16, 2012.

List of Subjects

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: December 16, 2011.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of the Federal Regulations is amended as follows:

PART 60--[AMENDED]

■ 1. The authority citation for part 60 continues to read as follows:

Authority: *42 U.S.C. 7401 et seq.*

Subpart A--[Amended]

■ 2. Section 60.17 is amended:

■ a. By redesignating paragraph (a)(93), added March 21, 2011, at *76 FR 15750,* and delayed indefinitely at *76 FR 28664,* May 18, 2011, as paragraph (a)(96);

■ b. By redesignating paragraphs (a)(91) and (a)(92) as paragraphs (a)(94) and (a)(95);

■ c. By redesignating paragraphs (a)(89) and (a)(90) as paragraphs (a)(91) and (a)(92);

■ d. By redesignating paragraphs (a)(54) through (a)(88) as paragraphs (a)(55) through (a)(89);

■ e. By adding paragraph (a)(54);

■ f. By adding paragraph (a)(90); and

■ g. By adding paragraph (a)(93) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) * * *

(54) ASTM D3699-08, Standard Specification for Kerosine, including Appendix X1, approved September 1, 2008, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

(90) ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, approved July 15, 2011, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

(93) ASTM D7467-10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, approved August 1, 2010, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

Subpart B--[Amended]

■ 3. Section 60.21 is amended as follows:

■ a. By revising paragraph (a).

■ b. By revising paragraph (f).

■ c. By removing paragraph (k).

§ 60.21 Definitions.

* * * * *

(a) *Designated pollutant* means any air pollutant, the emissions of which are subject to a standard of performance for new stationary sources, but for which air quality criteria have not been issued and that is not included on a list published under section 108(a) or section 112(b)(1)(A) of the Act.

* * * * *

(f) *Emission standard* means a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions.

* * * * *

■ 4. Section 60.24 is amended as follows:

■ a. By revising paragraph (b)(1).

■ b. By removing paragraph (h).

§ 60.24 Emission standards and compliance schedules.

* * * * *

(b) * * *

(1) Emission standards shall either be based on an allowance system or prescribe allowable rates of emissions except when it is clearly impracticable. Such cases will be identified in the guideline documents issued under § 60.22. Where emission standards prescribing equipment specifications are established, the plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such specifications, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed.

* * * * *

Subpart D--[Amended]

■ 5. The subpart heading for Subpart D is revised to read as follows:

Subpart D--Standards of Performance for Fossil-Fuel-Fired Steam Generators

■ 6. Section 60.40 is amended by revising paragraph (e) to read as follows:

§ 60.40 Applicability and designation of affected facility.

* * * * *

(e) Any facility subject to either subpart Da or KKKK of this part is not subject to this subpart.

■ 7. Section 60.41 is amended by adding the definition of "natural gas" in alphabetical order to read as follows:

§ 60.41 Definitions.

* * * * *

Natural gas means a fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, *natural gas* contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

* * * * *

■ 8. Section 60.42 is amended as follows:

■ a. By revising paragraph (a) introductory text.

■ b. By adding paragraph (d).

■ c. By adding paragraph (e).

§ 60.42 Standard for particulate matter (PM).

(a) Except as provided under paragraphs (b), (c), (d), and (e) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged

into the atmosphere from any affected facility any gases that:

* * * * *

(d) An owner or operator of an affected facility that combusts only natural gas is exempt from the PM and opacity standards specified in paragraph (a) of this section.

(e) An owner or operator of an affected facility that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2 or PM is exempt from the PM standards specified in paragraph (a) of this section.

■ 9. Section 60.45 is amended as follows:

■ a. By revising paragraph (a).

■ b. By revising paragraph (b) introductory text.

■ c. By revising paragraphs (b)(1) through (5).

■ d. By revising paragraph (b)(6) introductory text.

■ e. By revising paragraphs (b)(7)(i)(A) through (C).

■ f. By revising paragraph (b)(7)(ii)(B).

■ g. By adding paragraph (b)(8).

§ 60.45 Emissions and fuel monitoring.

(a) Each owner or operator of an affected facility subject to the applicable emissions standard shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a continuous emissions monitoring system

(CEMS) for measuring SO_2 emissions, NO_X emissions, and either oxygen (O_2) or carbon dioxide (CO_2) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS and COMS requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil-fuel-fired steam generator that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2 or PM, COMS for measuring the opacity of emissions and CEMS for measuring SO_2 emissions are not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis or fuel receipts.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring SO_2 emissions is not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis.

(3) Notwithstanding § 60.13(b), installation of a CEMS for NO_X may be delayed until after the initial performance tests under § 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of NO_X are less than 70 percent of the applicable standards in § 60.44, a CEMS for measuring NO_X emissions is not required. If the initial performance test results show that NO_X emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for NO_X within one year after the date of the initial performance tests under § 60.8 and comply with all

other applicable monitoring requirements under this part.

(4) If an owner or operator is not required to and elects not to install any CEMS for either SO_2 or NO[X], a CEMS for measuring either O_2 or CO_2 is not required.

(5) For affected facilities using a PM CEMS, a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in § 60.48Da of this part, or an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part a COMS is not required.

(6) A COMS for measuring the opacity of emissions is not required for an affected facility that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

* * * * *

(7) * * *

(i) * * *

(A) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part

performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(C) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

* * * * *

(ii) * * *

(B) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(8) A COMS for measuring the opacity of emissions is not required for an affected facility at which the owner or operator installs, calibrates, operates, and

maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

* * * * *

Subpart Da--[Amended]

10. The subpart heading for Subpart Da is revised to read as follows:

Subpart Da--Standards of Performance for Electric Utility Steam Generating Units

11. Section 60.40Da is amended by revising paragraphs (b)(1) and (e) to read as follows:

§ 60.40Da Applicability and designation of affected facility.

* * * * *

(b) * * *

(1) The IGCC electric utility steam generating unit is capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel) in the combustion turbine engine and associated heat recovery steam generator; and

* * * * *

(e) Applicability of this subpart to an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit is as specified in paragraphs (e)(1) through (3) of this section.

(1) Affected facilities (*i.e.* heat recovery steam generators used with duct burners) associated with a stationary combustion turbine that are capable of combusting more than 73 MW (250 MMBtu/h) heat

input of fossil fuel are subject to this subpart except in cases when the affected facility (*i.e.* heat recovery steam generator) meets the applicability requirements of and is subject to subpart KKKK of this part.

(2) For heat recovery steam generators use with duct burners subject to this subpart, only emissions resulting from the combustion of fuels in the steam generating unit (*i.e.* duct burners) are subject to the standards under this subpart. (The emissions resulting from the combustion of fuels in the stationary combustion turbine engine are subject to subpart GG or KKKK, as applicable, of this part.)

(3) Any affected facility that meets the applicability requirements and is subject to subpart Eb or subpart CCCC of this part is not subject to the emission standards under subpart Da.

12. Section 60.41Da is amended as follows:

a. By revising the definitions of "boiler operating day", "gaseous fuel", "integrated gasification combined cycle electric utility steam generating unit", "natural gas", "petroleum", "potential combustion concentration", and "steam generating unit".

b. By adding the definitions of "affirmative defense", "combined heat and power", "gross energy output", "net energy output", "out-of-control period", and "petroleum coke" in alphabetical order.

c. By removing the definitions of "available purchase power", "cogeneration", "dry flue gas desulfurization technology ", "electric utility company", "emergency condition", "emission rate period", "gross output", "interconnected", "net system capacity", "principal company", "responsible official", "spare flue gas desulfurization system module", "spinning

reserve", "system emergency reserves", and "system load"

§ 60.41Da Definitions.

* * * * *

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

* * * * *

Boiler operating day for units constructed, reconstructed, or modified before February 29, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, *boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

* * * * *

Combined heat and power, also known as "cogeneration," means a steam-generating unit that simultaneously produces both electric (and mechanical) and useful thermal energy from the same primary energy source.

* * * * *

Gaseous fuel means any fuel that is present as a gas at standard conditions and includes, but is not limited

to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

* * * * *

Gross energy output means:

(1) For facilities constructed, reconstructed, or modified before May 4, 2011, the gross electrical or mechanical output from the affected facility plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process);

(2) For facilities constructed, reconstructed, or modified after May 3, 2011, the gross electrical or mechanical output from the affected facility minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process);

(3) For combined heat and power facilities constructed, reconstructed, or modified after May 3, 2011, the gross electrical or mechanical output from the affected facility divided by 0.95 minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to

enhance the performance of the unit (*i.e.*, steam delivered to an industrial process);

(4) For a IGCC electric utility generating unit that coproduces chemicals constructed, reconstructed, or modified after May 3, 2011, the gross useful work performed is the gross electrical or mechanical output from the unit minus electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) that are associated with power production plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process). Auxiliary loads that are associated with power production are determined based on the energy in the coproduced chemicals compared to the energy of the syngas combusted in combustion turbine engine and associated duct burners.

* * * * *

Integrated gasification combined cycle electric utility steam generating unit or *IGCC electric utility steam generating unit* means an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction or repair. No solid fuel is directly burned in the unit during operation.

* * * * *

Natural gas means a fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, *natural gas* contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Net energy output means the gross energy output minus the parasitic load associated with power production. Parasitic load includes, but is not limited to, the power required to operate the equipment used for fuel delivery systems, air pollution control systems, wastewater treatment systems, ash handling and disposal systems, and other controls (*i.e.*, pumps, fans, compressors, motors, instrumentation, and other ancillary equipment required to operate the affected facility).

* * * * *

Out-of-control period means any period beginning with the quadrant corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit that indicates that the instrument is not measuring and recording within the applicable performance specifications and ending with the quadrant corresponding to the completion of an additional calibration error, linearity check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and

recording within the applicable performance specifications.

Petroleum for facilities constructed, reconstructed, or modified before May 4, 2011, means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, and residual oil. For units constructed, reconstructed, or modified after May 3, 2011, *petroleum* means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, residual oil, and petroleum coke.

Petroleum coke, also known as "petcoke," means a carbonization product of high-boiling hydrocarbon fractions obtained in petroleum processing (heavy residues). *Petroleum coke* is typically derived from oil refinery coker units or other cracking processes.

Potential combustion concentration means the theoretical emissions (nanograms per joule (ng/J), lb/MMBtu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems. For sulfur dioxide (SO_2) the potential combustion concentration is determined under § 60.50Da(c).

* * * * *

Steam generating unit for facilities constructed, reconstructed, or modified before May 4, 2011, means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included). For units constructed, reconstructed, or modified after May 3, 2011, *steam generating unit* means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam

(including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included) plus any integrated combustion turbines and fuel cells.

* * * * *

13. Section 60.42Da is revised to read as follows:

§ 60.42Da Standards for particulate matter (PM).

(a) Except as provided in paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before March 1, 2005, any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input.

(b) Except as provided in paragraphs (b)(1) and (b)(2) of this section, on and after the date the initial PM performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(1) An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart is exempt from the opacity standard specified in this paragraph (b) of this section.

(2) An owner or operator of an affected facility that combusts only natural gas is exempt from the opacity standard specified in paragraph (b) of this section.

(c) Except as provided in paragraphs (d) and (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of:

(1) 13 ng/J (0.030 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) For an affected facility that commenced construction or reconstruction, 0.1 percent of the

combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.9 percent reduction) when combusting solid, liquid, or gaseous fuel, or

(3) For an affected facility that commenced modification, 0.2 percent of the combustion concentration determined according to the procedure in § 60.48Da (o)(5) (99.8 percent reduction) when combusting solid, liquid, or gaseous fuel.

(e) Except as provided in paragraph (f) of this section, the owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after May 3, 2011, shall meet the requirements specified in paragraphs (e)(1) and (2) of this section.

(1) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator shall cause to be discharged into the atmosphere from that affected facility at all times except during periods of startup and shutdown, any gases that contain PM in excess of the applicable emissions limit specified in paragraphs (e)(1)(i) or (ii) of this section.

(i) For an affected facility which commenced construction or reconstruction, any gases that contain PM in excess of either:

(A) 11 ng/J (0.090 lb/MWh) gross energy output; or

(B) 12 ng/J (0.097 lb/MWh) net energy output.

(ii) For an affected facility which commenced modification, any gases that contain PM in excess of 13 ng/J (0.015 lb/MMBtu) heat input.

(2) During periods of startup and shutdown, the owner or operator shall meet the work practice

standards specified in Table 3 to subpart UUUUU of part 63.

(f) An owner or operator of an affected facility that meets the conditions in either paragraphs (f)(1) or (2) of this section is exempt from the PM emissions limits in this section.

(1) The affected facility combusts only gaseous or liquid fuels (excluding residual oil) with potential SO[2] emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and that does not use a post-combustion technology to reduce emissions of SO[2] or PM.

(2) The affected facility is operated under a PM commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da.

■ 14. Section 60.43Da is amended as follows:

■ a. The section heading is revised.

■ b. By revising paragraphs (a)(1) and (2).

■ c. By adding paragraphs (a)(3) and (4).

■ d. By removing and reserving paragraph (c).

■ e. By revising paragraph (f).

■ f. By revising paragraph (i).

■ g. By revising paragraph (k).

■ h. By adding paragraph (l).

■ i. By adding paragraph (m).

§ 60.43Da Standards for sulfur dioxide (SO2).

(a) * * *

(1) 520 ng/J (1.20 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction);

(2) 30 percent of the potential combustion concentration (70 percent) reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input;

(3) 180 ng/J (1.4 lb/MWh) gross energy output; or

(4) 65 ng/J (0.15 lb/MMBtu) heat input.

* * * * *

(f) The SO[2] standards under this section do not apply to an owner or operator of an affected facility that is operated under an SO[2] commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

* * * * *

(i) Except as provided in paragraphs (j) and (k) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO[2] in excess of the applicable emissions limit specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility which commenced construction, any gases that contain SO[2] in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 5 percent of the potential combustion concentration (95 percent reduction).

(2) For an affected facility which commenced reconstruction, any gases that contain SO[2] in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 5 percent of the potential combustion concentration (95 percent reduction).

(3) For an affected facility which commenced modification, any gases that contain SO[2] in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction).

* * * * *

(k) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO[2] in excess of the applicable emissions limit specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO[2] in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO[2] in excess of 230 ng/J (0.54 lb/MMBtu) heat input.

(l) Except as provided in paragraphs (j) and (m) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility for which construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO[2] in excess of the applicable emissions limit specified in paragraphs (l)(1) and (2) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain SO[2] in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 140 ng/J (1.2 lb/MWh) net energy output; or

(iii) 3 percent of the potential combustion concentration (97 percent reduction).

(2) For an affected facility which commenced modification, any gases that contain SO[2] in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 10 percent of the potential combustion concentration (90 percent reduction).

(m) On and after the date on which the initial performance test is completed or required to be

completed under § 60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area for which construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO[2] in excess of the applicable emissions limit specified in paragraphs (m)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO[2] in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO[2] in excess of 230 ng/J (0.54 lb/MMBtu) heat input.

15. Section 60.44Da is revised to read as follows:

§ 60.44Da Standards for nitrogen oxides (NO[X]).

(a) Except as provided in paragraph (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before July 10, 1997 any gases that contain NO[X] (expressed as NO[2]) in excess of the applicable emissions limit in paragraphs (a)(1) and (2) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere any gases that contain

NO[X] in excess of the emissions limit listed in the following table as applicable to the fuel type combusted and as determined on a 30-boiler operating day rolling average basis.

Fuel type	Emission limit for heat input ng/J	lb/MMBtu
Gaseous fuels:		
Coal-derived fuels	210	0.50
All other fuels	86	0.20
Liquid fuels:		
Coal-derived fuels	210	0.50
Shale oil	210	0.50
All other fuels	130	0.30
Solid fuels:		
Coal-derived fuels	210	0.50
Any fuel containing more than 25%, by weight, coal refuse	(fn1)	(fn1)
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace fn2	340	0.80
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit fn2	260	0.60
Subbituminous coal	210	0.50
Bituminous coal	260	0.60
Anthracite coal	260	0.60
All other fuels	260	0.60

fn1 Exempt from NOX standards and NOX monitoring requirements.

fn2 Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

(2) When two or more fuels are combusted simultaneously in an affected facility, the applicable emissions limit (E[n]) is determined by proration using the following formula:

$$En = \frac{(86w + 130x + 210y + 260z + 340v)}{100}$$

Where:

En = Applicable NO[X] emissions limit when multiple fuels are combusted simultaneously (ng/J heat input);

w = Percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x = Percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y = Percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;

z = Percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v = Percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(b) [Reserved]

(c) [Reserved]

(d) Except as provided in paragraph (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or

modification after July 9, 1997, but before March 1, 2005, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO[X] (expressed as NO[2]) in excess of the applicable emissions limit specified in paragraphs (d)(1) and (2) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NO[X] in excess of 200 ng/J (1.6 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NO[X] in excess of 65 ng/J (0.15 lb/MMBtu) heat input.

(e) Except as provided in paragraphs (f) and (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO[X] (expressed as NO[2]) in excess of the applicable emissions limit specified in paragraphs (e)(1) through (3) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NO[X] in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NO[X] in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input.

(3) For an affected facility which commenced modification, any gases that contain NO[X] in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input.

(f) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an IGCC electric utility steam generating unit subject to the provisions of this subpart and for which construction, reconstruction, or modification commenced after February 28, 2005 but before May 4, 2011, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) Except as provided for in paragraphs (f)(2) and (3) of this section, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO[X] (expressed as NO[2]) in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) When burning liquid fuel exclusively or in combination with solid-derived fuel such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO[X] (expressed as NO[2]) in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

(3) In cases when during a 30-boiler operating day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the clock hours

in the 30-day compliance period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO[X] (expressed as NO[2]) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

(g) Except as provided in paragraphs (h) of this section and § 60.45Da, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO[X] (expressed as NO[2]) in excess of the applicable emissions limit specified in paragraphs (g)(1) through (3) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NO[X] in excess of either:

(i) 88 ng/J (0.70 lb/MWh) gross energy output; or

(ii) 95 ng/J (0.76 lb/MWh) net energy output.

(2) For an affected facility which commenced construction or reconstruction and that burns 75 percent or more coal refuse (by heat input) on a 12-month rolling average basis, any gases that contain NO[X] in excess of either:

(i) 110 ng/J (0.85 lb/MWh) gross energy output; or

(ii) 120 ng/J (0.92 lb/MWh) net energy output.

(3) For an affected facility which commenced modification, any gases that contain NO[X] in excess of 140 ng/J (1.1 lb/MWh) gross energy output.

(h) The NO[X] emissions limits under this section do not apply to an owner or operator of an affected facility which is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

• 16. Section 60.45Da is revised to read as follows:

§ 60.45Da Alternative standards for combined nitrogen oxides (NO[X]) and carbon monoxide (CO).

(a) The owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011 as alternate to meeting the applicable NO[X] emissions limits specified in § 60.44D a may elect to meet the applicable standards for combined NO[X] and CO specified in paragraph (b) of this section.

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO[X] (expressed as NO[2]) plus CO in excess of the applicable emissions limit specified in paragraphs (b)(1) through (3) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NO[X] plus CO in excess of either:

(i) 140 ng/J (1.1 lb/MWh) gross energy output; or

(ii) 150 ng/J (1.2 lb/MWh) net energy output.

(2) For an affected facility which commenced construction or reconstruction and that burns 75 percent or more coal refuse (by heat input) on a 12-month rolling average basis, any gases that contain NO[X] plus CO in excess of either:

(i) 160 ng/J (1.3 lb/MWh) gross energy output; or

(ii) 170 ng/J (1.4 lb/MWh) net energy output.

(3) For an affected facility which commenced modification, any gases that contain NO[X] plus CO in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

- 17. Section 60.47Da is amended as follows:
- a. By revising paragraph (c).
- b. By adding paragraph (f).
- c. By adding paragraph (g).
- d. By adding paragraph (h).
- e. By adding paragraph (i).

§ 60.47Da Commercial demonstration permit.

* * * * *

(c) An owner or operator of an affected facility that uses fluidized bed combustion (atmospheric or pressurized) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO[2] emission reduction requirements under § 60.43Da(a) but must, as a minimum, reduce SO[2] emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J

(1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

* * * * *

(f) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the total PM emission reduction requirements under § 60.42Da but must, as a minimum, reduce PM emissions to less than 6.4 ng/J (0.015 lb/MMBtu) heat input.

(g) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the SO[2] standards or emission reduction requirements under § 60.43Da but must, as a minimum, reduce SO[2] emissions to 5 percent of the potential combustion concentration (95 percent reduction) or to less than 180 ng/J (1.4 lb/MWh) gross energy output on a 30-boiler operating day rolling average basis.

(h) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions control system or advanced combustion controls who is issued a commercial demonstration permit by the Administrator is not subject to the NO[X] standards or emission reduction requirements under § 60.44Da but must, as a minimum, reduce NO[X] emissions to less than 130 ng/J (1.0 lb/MWh) or the combined NO[X] plus CO emissions to less than 180 ng/J (1.4 lb/MWh) gross energy output on a 30-boiler operating day rolling average basis.

(i) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category listed in the following table.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Multi-pollutant Emission Control	SO[2]	1,000
Multi-pollutant Emission Control	NO[X]	1,000
Multi-pollutant Emission Control	PM	1,000
Pressurized Fluidized Bed Combustion	SO[2]	1,000
Pressurized Fluidized Bed Combustion	NO[X]	1,000
Pressurized Fluidized Bed Combustion	PM	1,000
Advanced Combustion Controls	NO[X]	1,000

- 18. Section 60.48Da is amended as follows:
- a. By revising paragraphs (a) through (g).
- b. By revising paragraph (i).
- c. By revising paragraph (k)(1)(i).
- d. By revising paragraph (k)(2)(i).
- e. By revising paragraph (k)(2)(iv).
- f. By removing and reserving paragraph (l).
- g. By revising paragraph (m).
- h. By revising paragraph (n).
- i. By revising paragraphs (p)(5), (7), and (8).
- j. By adding paragraph (r).
- k. By adding paragraph (s).

§ 60.48Da Compliance provisions.

(a) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, the applicable PM emissions limit and opacity standard under § 60.42Da, SO[2] emissions limit under § 60.43Da, and NO[X] emissions limit under § 60.44Da apply at all times except during periods of startup, shutdown, or malfunction. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, the applicable SO[2] emissions limit under § 60.43Da, NO[X] emissions limit under § 60.44Da, and NO[X] plus CO emissions limit under § 60.45Da apply at all times. The applicable PM emissions limit and opacity standard under § 60.42Da apply at all times except during periods of startup and shutdown.

(b) After the initial performance test required under § 60.8, compliance with the applicable SO[2] emissions limit and percentage reduction requirements under § 60.43Da, NO[X] emissions limit under § 60.44Da, and NO[X] plus CO emissions limit under § 60.45Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for both SO[2], NO[X] or NO[X] plus CO as applicable, and a new percent reduction for SO[2] are calculated to demonstrate compliance with the standards.

(c) For the initial performance test required under § 60.8, compliance with the applicable SO[2] emissions limits and percentage reduction requirements under § 60.43Da, the NO[X] emissions limits under § 60.44Da, and the NO[X] plus CO emissions limits under § 60.45Da is based on the average emission

rates for SO[2], NO[X], CO, and percent reduction for SO[2] for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(d) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable 30-boiler operating day rolling average SO[2] and NO[X] emissions limits is determined by calculating the arithmetic average of all hourly emission rates for SO[2] and NO[X] for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average SO[2] and NO[X] emissions limits is determined by dividing the sum of the SO[2] and NO[X] emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, as applicable, for the 30 successive boiler operating days.

(e) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable SO[2] percentage reduction requirements is determined based on the average inlet and outlet SO[2] emission rates for the 30 successive boiler operating days. For affected facilities for which construction, modification, or

reconstruction commenced after May 3, 2011, compliance with applicable SO[2] percentage reduction requirements is determined based on the "as fired" total potential emissions and the total outlet SO[2] emissions for the 30 successive boiler operating days.

(f) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable daily average PM emissions limits is determined by calculating the arithmetic average of all hourly emission rates for PM each boiler operating day, except for data obtained during startup, shutdown, and malfunction. Daily averages are only calculated for boiler operating days that have non-out-of-control data for at least 18 hours of unit operation during which the standard applies. Instead, all of the non-out-of-control hourly emission rates of the operating day(s) not meeting the minimum 18 hours non-out-of-control data daily average requirement are averaged with all of the non-out-of-control hourly emission rates of the next boiler operating day with 18 hours or more of non-out-of-control PM CEMS data to determine compliance. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable daily average PM emissions limits is determined by dividing the sum of the PM emissions for the 30 successive boiler operating days by the sum of the gross useful output or net energy output, as applicable, for the 30 successive boiler operating days.

(g) For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average NO[X] plus CO

emissions limit is determined by dividing the sum of the NO[X] plus CO emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, as applicable, for the 30 successive boiler operating days.

* * * * *

(i) Compliance provisions for sources subject to § 60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), (f), or (g). The owner or operator shall calculate NO[X] emissions as 1.194 x 10<-7> lb/scf-ppm times the average hourly NO[X] output concentration in ppm (measured according to the provisions of § 60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of § 60.49Da(l) or § 60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable. Alternatively, for oil-fired and gas-fired units, NO[X] emissions may be calculated by multiplying the hourly NO[X] emission rate in lb/MMBtu (measured by the CEMS required under § 60.49Da(c) and (d)), by the hourly heat input rate (measured according to the provisions of § 60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(k) * * *

(l) * * *

(i) The emission rate (E) of NO[X] shall be computed using Equation 2 in this section:

$$E = \frac{(Csg \times Qsg) - (Cte \times Qte)}{(Osg \times h)} \qquad \text{(Eq. 2)}$$

Where:

E = Emission rate of NO[X] from the duct burner, ng/J (lb/MWh) gross energy output;

C[sg] = Average hourly concentration of NO[X] exiting the steam generating unit, ng/dscm (lb/dscf);

C[te] = Average hourly concentration of NO[X] in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf);

Q[sg] = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/h (dscf/h);

Q[te] = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/h (dscf/h);

O[sg] = Average hourly gross energy output from steam generating unit, J/h (MW); and

h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

* * * * *

(2) * * *

(i) The emission rate (E) of NO[X] shall be computed using Equation 3 in this section:

$$E = \frac{(Csg \times Qsg)}{Occ} \qquad (Eq.\ 3)$$

Where:

E = Emission rate of NO[X] from the duct burner, ng/J (lb/MWh) gross energy output;

C[sg] = Average hourly concentration of NO[X] exiting the steam generating unit, ng/dscm (lb/dscf);

Q[sg] = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/h (dscf/h); and

O[cc] = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

* * * * *

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in § 60.49Da(l), determine the mass rate (lb/h) of NO[X] emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of part 75 of this chapter. If this compliance option is selected, the emission rate (E) of NO[X] shall be computed using Equation 4 in this section:

$$E = \frac{(ERsg \times Hcc)}{Occ} \qquad (Eq. 4)$$

Where:

E = Emission rate of NO[X] from the duct burner, ng/J (lb/MWh) gross energy output;

ER[sg] = Average hourly emission rate of NO[X] exiting the steam generating unit heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part, ng/J (lb/MMBtu);

H[cc] = Average hourly heat input rate of entire combined cycle unit, J/h (MMBtu/h); and

O[cc] = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

* * * * *

(m) Compliance provisions for sources subject to § 60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), (j)(3)(i), (l)(1)(i), (l)(1)(ii), or (l)(2). The owner or

operator shall calculate SO[2] emissions as 1.660 x 10<-7> lb/scf-ppm times the average hourly SO[2] output concentration in ppm (measured according to the provisions of § 60.49Da(b)), times the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable. Alternatively, for oil-fired and gas-fired units, SO[2] emissions may be calculated by multiplying the hourly SO[2] emission rate (in lb/MMBtu), measured by the CEMS required under § 60.49Da, by the hourly heat input rate (measured according to the provisions of § 60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(n) Compliance provisions for sources subject to § 60.42Da(c)(1) or (e)(1)(i). The owner or operator shall calculate PM emissions by multiplying the average hourly PM output concentration (measured according to the provisions of § 60.49Da(t)), by the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), and dividing by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

* * * * *

(p) * * *

(5) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30-boiler operating day rolling average basis. Beginning on January 1, 2012, non-

out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-boiler operating day rolling average basis.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

* * * * *

(7) All non-out-of-control CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(5) of this section are not met.

(8) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, non-out-of-control emissions data for a minimum of 90 percent (only 75 percent is required prior to January 1, 2012) of all operating hours per 30-boiler operating day rolling average.

* * * * *

(r) Compliance provisions for sources subject to § 60.45Da. To determine compliance with the NO[X] plus CO emissions limit, the owner or operator shall use the procedures specified in paragraphs (r)(1) through (3) of this section.

(1) Calculate NO[X] emissions as 1.194 x 10<-7> lb/scf-ppm times the average hourly NO[X] output concentration in ppm (measured according to the provisions of § 60.49Da(c)), times the average hourly

flow rate (measured in scfh, according to the provisions of § 60.49Da(l) or § 60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(2) Calculate CO emissions by multiplying the average hourly CO output concentration (measured according to the provisions of § 60.49Da(u), by the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), and dividing by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(3) Calculate NO[X] plus CO emissions by summing the NO[X] emissions results from paragraph (r)(1) of this section plus the CO emissions results from paragraph (r)(2) of this section.

(s) Affirmative defense for exceedance of emissions limit during malfunction. In response to an action to enforce the standards set forth in paragraph §§ 60.42Da, 60.43Da, 60.44Da, and 60.45Da, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at *40 CFR 60.2*. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense as specified in paragraphs (s)(1) and (2) of this section. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (s)(2) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design, or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emissions limits were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount, and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction or, if it is not possible to determine within two business days whether the malfunction caused or contributed to an exceedance, no later than two business days after the owner or operator knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in § 63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set

forth in paragraph (s)(1) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

- 19. Section 60.49Da is amended as follows:
- a. By revising paragraphs (a)(1) and (2).
- b. By revising paragraph (a)(3) introductory text.
- c. By revising paragraph (a)(3)(ii).
- d. By revising paragraph (a)(3)(iii)(B).
- e. By adding paragraph (a)(4).
- f. By revising paragraph (b) introductory text.
- g. By revising paragraph (b)(2).
- h. By revising paragraph (e).
- i. By revising paragraph (k) introductory text.
- j. By revising paragraph (k)(3).
- k. By revising paragraph (l).
- l. By removing and reserving paragraph (p).
- m. By removing and reserving paragraph (q).
- n. By removing and reserving paragraph (r).
- o. By revising paragraph (t).
- p. By revising paragraph (u)(1)(iii).
- q. By revising paragraph (v)(4).

§ 60.49Da Emission monitoring.

(a) * * *

(1) Except as provided for in paragraphs (a)(2) and (4) of this section, the owner or operator of an affected facility subject to an opacity standard, shall install, calibrate, maintain, and operate a COMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO[2] control system), alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(2) As an alternative to the monitoring requirements in paragraph (a)(1) of this section, an owner or operator of an affected facility that meets the conditions in either paragraph (a)(2)(i), (ii), (iii), or (iv) of this section may elect to monitor opacity as specified in paragraph (a)(3) of this section.

(i) The affected facility uses a fabric filter (baghouse) to meet the standards in § 60.42Da and a bag leak detection system is installed and operated according to the requirements in paragraphs § 60.48Da(o)(4)(i) through (v);

(ii) The affected facility burns only gaseous or liquid fuels (excluding residual oil) with potential SO[2] emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and does not use a post-combustion technology to reduce emissions of SO[2] or PM;

(iii) The affected facility meets all of the conditions specified in paragraphs (a)(2)(iii)(A) through (C) of this section.

(A) No post-combustion technology (except a wet scrubber) is used for reducing PM, SO[2], or CO emissions;

(B) Only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur are burned; and

(C) Emissions of CO discharged to the atmosphere are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis as demonstrated by the use of a CEMS measuring CO emissions according to the procedures specified in paragraph (u) of this section; or

(iv) The affected facility uses an ESP and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part.

(3) The owner or operator of an affected facility that meets the conditions in paragraph (a)(2) of this section may, as an alternative to using a COMS, elect to monitor visible emissions using the applicable procedures specified in paragraphs (a)(3)(i) through (iv) of this section. The opacity performance test requirement in paragraph (a)(3)(i) must be conducted by April 29, 2011, within 45 days after stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later.

* * * * *

(ii) Except as provided in paragraph (a)(3)(iii) or (iv) of this section, the owner or operator shall conduct

subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a)(3)(i) of this section according to the applicable schedule in paragraphs (a)(3)(ii)(A) through (a)(3)(ii)(C) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(A) If the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(C) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(iii) * * *

(B) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(4) An owner or operator of an affected facility that is subject to an opacity standard under § 60.42a(b) is not required to operate a COMS provided that affected facility meets the conditions in either paragraph (a)(4)(i) or (ii) of this section.

(i) The affected facility combusts only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO[2] emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.51a(d).

(ii) The owner or operator of the affected facility installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO[2] emissions, except where natural gas and/or liquid fuels (excluding residual oil) with potential SO[2] emissions rates of 26 ng/J (0.060 lb/ MMBtu) or less are the only fuels combusted, as follows:

* * * * *

(2) For a facility that qualifies under the numerical limit provisions of § 60.43Da, SO[2] emissions are only monitored as discharged to the atmosphere.

* * * * *

(e) The CEMS under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

* * * * *

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross energy output for sources demonstrating compliance with an output-based standard.

* * * * *

(3) For an affected facility generating process steam in combination with electrical generation, the gross energy output is determined according to the definition of "gross energy output" specified in § 60.41Da that is applicable to the affected facility.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B of this part and the calibration drift (CD) assessment, relative accuracy test audit (RATA), and reporting provisions of procedure 1 of appendix F of this part, and record the output of the system, for

measuring the volumetric flow rate of exhaust gases discharged to the atmosphere; or

* * * * *

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under § 60.42Da shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected facility demonstrating compliance with the input-based emissions limit in § 60.42Da may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) * * *

(1) * * *

(iii) At a minimum, non-out-of-control 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-boiler operating day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

* * * * *

(v) * * *

(4) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.*, reference method) data and performance test (*i.e.*, compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic

Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFire database.

* * * * *

- 20. Section 60.50Da is amended as follows:
- a. By revising paragraph (b).
- b. By removing paragraph (g).
- c. By removing paragraph (h).
- d. By removing paragraph (i).

§ 60.50Da Compliance determination procedures and methods.

* * * * *

(b) In conducting the performance tests to determine compliance with the PM emissions limits in § 60.42Da, the owner or operator shall meet the requirements specified in paragraphs (b)(1) through (3) of this section.

(1) The owner or operator shall measure filterable PM to determine compliance with the applicable PM emissions limit in § 60.42Da as specified in paragraphs (b)(1)(i) through (ii) of this section.

(i) The dry basis F factor (O[2]) procedures in Method 19 of appendix A of this part shall be used to compute the emission rate of PM.

(ii) For the PM concentration, Method 5 of appendix A of this part shall be used for an affected facility that does not use a wet FGD. For an affected facility that

uses a wet FGD, Method 5B of appendix A of this part shall be used downstream of the wet FGD.

(A) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160 +/- 14 [degrees] C (320 +/- 25 [degrees] F).

(B) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B of appendix A of this part shall be used to determine the O[2] concentration. The O[2] sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O[2] traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O[2] traverse points. If the grab sampling procedure is used, the O[2] concentration for the run shall be the arithmetic mean of the sample O[2] concentrations at all traverse points.

(2) In conjunction with a performance test performed according to the requirements in paragraph (b)(1) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after May 3, 2011, shall measure condensable PM using Method 202 of appendix M of part 51.

(3) Method 9 of appendix A of this part and the procedures in § 60.11 shall be used to determine opacity.

* * * * *

- 21. Section 60.51Da is amended as follows:
- a. By revising paragraph (a).
- b. By revising paragraph (b)(5).
- c. By revising paragraph (d).
- d. By removing and reserving paragraph (g).
- e. By revising paragraph (k).

§ 60.51Da Reporting requirements.

(a) For SO[2], NO[X], PM, and NO[X] plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) must be reported to the Administrator.

(b) * * *

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, or malfunction.

* * * * *

(d) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) and conducting performance tests using Method 9 of appendix A-4 of this part shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraph (d)(1) of this section.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or

operator shall keep the records including the information specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets.

(2) [Reserved]

* * * * *

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO[2] and/or NO[X] and/or opacity in lieu of submitting the written reports required under paragraphs (b) and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period.

§ 60.52Da [Amended]

• 22. Section 60.52Da is amended by removing and reserving paragraph (a).

Subpart Db--[Amended]

• 23. Section 60.40b is amended as follows:

• a. By revising paragraph (c).

- b. By revising paragraph (h).
- c. By revising paragraph (i).
- d. By adding paragraph (l).
- e. By adding paragraph (m).

§ 60.40b Applicability and delegation of authority.

* * * * *

(c) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO[X] standards under this subpart and the SO[2] standards under subpart J or subpart Ja of this part, as applicable.

* * * * *

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, subpart AAAA, or subpart CCCC of this part is not subject to this subpart.

(i) Affected facilities (*i.e.*, heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other affected facilities (*i.e.* heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the affected facility (*i.e.* heat recovery steam generator) is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

* * * * *

(l) Affected facilities that also meet the applicability requirements under subpart BB of this part (Standards of Performance for Kraft Pulp Mills) are subject to the SO[2] and NO[X] standards under this subpart and the PM standards under subpart BB.

(m) Temporary boilers are not subject to this subpart.

24. Section 60.41b is amended by revising the definition of "distillate oil", and adding the definition of "temporary boiler" in alphabetical order to read as follows:

§ 60.41b Definitions.

* * * * *

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

* * * * *

Temporary boiler means any gaseous or liquid fuel-fired steam generating unit that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

* * * * *

• 25. Section 60.43b is amended by revising paragraph (f) to read as follows:

§ 60.43b Standard for particulate matter (PM).

* * * * *

(f) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts

coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and is subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less is exempt from the opacity standard specified in this paragraph.

* * * * *

- 26. Section 60.44b is amended as follows:
- a. The section heading is revised.
- b. By revising paragraph (b) introductory text.
- c. By revising paragraph (c).
- d. By revising paragraph (d).
- e. By revising paragraph (e).
- f. By revising paragraph (l)(1).

§ 60.44b Standard for nitrogen oxides (NO[X]).

* * * * *

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of only coal, oil, or natural gas shall cause to be discharged into the

atmosphere from that affected facility any gases that contain NO[X] in excess of a limit determined by the use of the following formula:

* * * * *

(c) Except as provided under paragraph (d) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, natural gas (or any combination of the three), and wood, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO[X] in excess of the emission limit for the coal, oil, natural gas (or any combination of the three), combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section. This standard does not apply to an affected facility that is subject to and in compliance with a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, natural gas (or any combination of the three).

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas and/or distillate oil with a potential SO[2] emissions rate of 26 ng/J (0.060 lb/MMBtu) or less with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO[X] in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas, distillate oil, or a mixture of these fuels of

10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas, distillate oil, or a mixture of these fuels.

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts only coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO[X] in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

* * * * *

(l) * * *

(1) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. The affected facility is not subject to this limit if it is subject to and in compliance with a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas (or any combination of the three); or

* * * * *

• 27. Section 60.46b is amended by revising paragraph (j)(14) to read as follows:

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

* * * * *

(j) * * *

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.*, reference method) data and performance test (*i.e.*, compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

• 28. Section 60.48b is amended as follows:

• a. By revising paragraph (a) introductory text.

• b. By revising paragraphs (a)(1)(i) through (iii)

• c. By revising paragraph (a)(2)(ii).

• d. By revising paragraph (j) introductory text.

• e. By revising paragraph (j)(5).

• f. By revising paragraph (j)(6).

• g. By adding paragraph (j)(7).

• h. By adding paragraph (l).

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) * * *

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

* * * * *

(2) * * *

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

* * * * *

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section § 60.48Da of this part; or

(6) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part; or

(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

* * * * *

(l) An owner or operator of an affected facility that is subject to an opacity standard under § 60.43b(f) is not required to operate a COMS provided that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO[2] emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with

the excess emissions report required under § 60.49b(h).

• 29. Section 60.49b is amended by revising paragraph (r)(1) to read as follows.

§ 60.49b Reporting and recordkeeping requirements.

* * * * *

(r) * * *

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in § 60.42b(j) or § 60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in § 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

* * * * *

Subpart Dc--[Amended]

- 30. Section 60.40c is amended as follows:
- a. By revising paragraph (a).
- b. By revising paragraph (e).
- c. By revising paragraph (f).
- d. By revising paragraph (g).
- e. By adding paragraph (h).
- f. By adding paragraph (i).

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

* * * * *

(e) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of

fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO[X] standards under this subpart and the SO[2] standards under subpart J or subpart Ja of this part, as applicable.

(i) Temporary boilers are not subject to this subpart.

• 31. Section 60.41c is amended as follows:

• a. By removing the definition of "Cogeneration."

• b. By revising the definition of "Distillate oil."

• c. By adding a definition of "Temporary boiler" in alphabetical order.

§ 60.41c Definitions.

* * * * *

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by

the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

* * * * *

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO[2] emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at

least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

* * * * *

• 32. Section 60.42c is amended as follows:

• a. By revising paragraph (c)(1) and (3).

• b. By revising paragraph (d).

• c. By revising paragraph (e)(1)(ii).

• d. By revising paragraph (h) introductory text.

• e. By revising paragraph (h)(3).

• f. By adding paragraph (h)(4).

§ 60.42c Standard for sulfur dioxide (SO2).

* * * * *

(c) * * *

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;

* * * * *

(3) Affected facilities located in a noncontinental area; or

* * * * *

(d) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO[2]

in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) * * *

(1) * * *

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and

* * * * *

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f), as applicable.

* * * * *

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

* * * * *

- 33. Section 60.43c is amended as follows:
- a. By revising paragraph (a) introductory text.
- b. By revising paragraph (b) introductory text.

- c. By revising paragraph (c).
- d. By revising paragraphs (e)(1), (3), and (4).

§ 60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

* * * * *

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

* * * * *

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no

owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

* * * * *

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

* * * * *

(3) On and after the date on which the initial performance test is completed or is required to be

completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.5(weight percent sulfur oil with other fuels not subject to a PM standard under § 60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO[2] emissions is not subject to the PM limit in this section.

- 34. Section 60.45c is amended as follows:
- a. By revising paragraph (c)(14).
- b. By revising paragraph (d).

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

* * * * *

(c) * * *

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.*, reference method) data and performance test (*i.e.*, compliance test) data,

except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under § 60.43c(e)(4) shall follow the applicable procedures under § 60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

- 35. Section 60.47c is amended as follows:
- a. By revising paragraph (a) introductory text.
- b. By revising paragraphs (a)(1)(i) through (iii).
- c. By revising paragraph (a)(2)(ii).
- d. By revising paragraph (f).
- e. By removing paragraph (g).

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in

§ 60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) * * *

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10

percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

* * * * *

(2) * * *

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(f) An owner or operator of an affected facility that is subject to an opacity standard in § 60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section § 60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section § 60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.48c(c).

Subpart HHHH--[Removed and Reserved]

• 36. Subpart HHHH is removed and reserved.

PART 63--[AMENDED]

• 37. The authority citation for 40 CFR Part 63 continues to read as follows:

Authority: *42 U.S.C. 7401, et seq.*

Subpart A--[Amended]

• 38. Section 63.14 is amended as follows:

• a. By adding paragraphs (b)(19) and (20).

• b. By adding paragraphs (b)(22) and (23).

• c. By adding paragraphs (b)(69) through (72).

• d. By revising paragraph (i)(1).

Supreme Court, U.S.
FILED
JUL 14 2014
OFFICE OF THE CLERK

14- 49

NO. 14-___

IN THE

Supreme Court of the United States

NATIONAL MINING ASSOCIATION, PETITIONER

v.

ENVIRONMENTAL PROTECTION AGENCY, RESPONDENT

ON PETITION FOR WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

PETITION FOR A WRIT OF CERTIORARI
VOLUME 3 of 4

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WILSON-EPES PRINTING CO., INC. – (202) 789-0096 – WASHINGTON, D. C. 20002

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§ 63.14 Incorporation by reference.

* * * * *

(b) * * *

(19) ASTM D95-05 (Reapproved 2010), Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation, approved May 1, 2010, IBR approved for § 63.10005(i)(4)(i).

(20) ASTM Method D388-05, Standard Classification of Coals by Rank, approved September 15, 2005, IBR approved for § 63.10042.

* * * * *

(22) ASTM Method D396-10, Standard Specification for Fuel Oils, including Appendix X1, approved October 1, 2010, IBR approved for § 63.10042.

(23) ASTM D4006-11, Standard Test Method for Water in Crude Oil by Distillation, including Annex A1 and Appendix X1, approved June 1, 2011, IBR approved for § 63.10005(i)(4)(ii).

* * * * *

(69) ASTM D4057-06 (Reapproved 2011), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, including Annex A1, approved June 1, 2011, IBR approved for § 63.10005(i)(4)(iv).

(70) ASTM D4177-95 (Reapproved 2010), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, including Annexes A1 through A6 and Appendices X1 and X2, approved May 1, 2010, IBR approved for § 63.10005(i)(4)(iii).

(71) ASTM D6348-03 (Reapproved 2010), Standard Test Method for Determination of Gaseous

Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, including Annexes A1 through A8, approved October 1, 2010, IBR approved for table 1 to subpart UUUUU of this part, table 2 to subpart UUUUU of this part, table 5 to subpart UUUUU of this part, and appendix B to subpart UUUUU of this part.

(72) ASTM D6784-02 (Reapproved 2008), Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved April 1, 2008, IBR approved for table 5 to subpart UUUUU of this part, and appendix A to subpart UUUUU of this part.

* * * * *

(i) * * *

(1) ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses [part 10, Instruments and Apparatus]," IBR approved for §§ 63.309(k)(1)(iii), 63.865(b), 63.3166(a)(3), 63.3360(e)(1)(iii), 63.3545(a)(3), 63.3555(a)(3), 63.4166(a)(3), 63.4362(a)(3), 63.4766(a)(3), 63.4965(a)(3), 63.5160(d)(1)(iii), 63.9307(c)(2), 63.9323(a)(3), 63.11148(e)(3)(iii), 63.11155(e)(3), 63.11162(f)(3)(iii) and (f)(4), 63.11163(g)(1)(iii) and (g)(2), 63.11410(j)(1)(iii), 63.11551(a)(2)(i)(C), table 5 to subpart DDDDD of this part, table 1 to subpart ZZZZZ of this part, table 4 to subpart JJJJJJ of this part, and table 5 to subpart UUUUU of this part.

* * * * *

• 39. Part 63 is amended by adding subpart UUUUU to read as follows:

Subpart UUUUU--National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Sec.

What This Subpart Covers

63.9980 What is the purpose of this subpart?

63.9981 Am I subject to this subpart?

63.9982 What is the affected source of this subpart?

63.9983 Are any EGUs not subject to this subpart?

63.9984 When do I have to comply with this subpart?

63.9985 What is a new EGU?

Emission Limitations and Work Practice Standards

63.9990 What are the subcategories of EGUs?

63.9991 What emission limitations, work practice standards, and operating limits must I meet?

General Compliance Requirements

63.10000 What are my general requirements for complying with this subpart?

63.10001 Affirmative defense for exceedence of emission limit during malfunction.

Testing and Initial Compliance Requirements

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63.10006 When must I conduct subsequent performance tests or tune-ups?

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63.10008 [Reserved]

63.10009 May I use emissions averaging to comply with this subpart?

63.10010 What are my monitoring, installation, operation, and maintenance requirements?

63.10011 How do I demonstrate initial compliance with the emission limitations and work practice standards?

Continuous Compliance Requirements

63.10020 How do I monitor and collect data to demonstrate continuous compliance?

63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

Notifications, Reports, and Records

63.10030 What notifications must I submit and when?

63.10031 What reports must I submit and when?

63.10032 What records must I keep?

63.10033 In what form and how long must I keep my records?

Other Requirements and Information

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63.10041 Who implements and enforces this subpart?

63.10042 What definitions apply to this subpart?

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Table 1 to Subpart UUUUU of Part 63--Emission Limits for New or Reconstructed EGUs

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

Table 3 to Subpart UUUUU of Part 63--Work Practice Standards

Table 4 to Subpart UUUUU of Part 63--Operating Limits for EGUs

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

Table 6 to Subpart UUUUU of Part 63--Establishing PM CPMS Operating Limits

Table 7 to Subpart UUUUU of Part 63--Demonstrating Continuous Compliance

Table 8 to Subpart UUUUU of Part 63--Reporting Requirements

Table 9 to Subpart UUUUU of Part 63--Applicability of General Provisions to Subpart UUUUU

Appendix A to Subpart UUUUU--Hg Monitoring Provisions

Appendix B to Subpart UUUUU--HCl and HF Monitoring Provisions

Subpart UUUUU--National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

What This Subpart Covers

§ 63.9980 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs) as defined in § 63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

§ 63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU as defined in § 63.10042 of this subpart.

§ 63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of two or more new, reconstructed, and existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

(1) The affected source of this subpart is the collection of all existing coal- or oil-fired EGUs, as defined in 63.10042, within a subcategory.

(2) The affected source of this subpart is each new or reconstructed coal- or oil-fired EGU as defined in 63.10042.

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011, and you

meet the applicability criteria at the time you commence construction.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after May 3, 2011, and you meet the applicability criteria at the time you commence reconstruction.

(d) An EGU is existing if it is not new or reconstructed. An existing electric steam generating unit that meets the applicability requirements after the effective date of this final rule due to a change process (*e.g.*, fuel or utilization) is considered to be an existing source under this subpart.

§ 63.9983 Are any EGUs not subject to this subpart?

The types of electric steam generating units listed in paragraphs (a) through (d) of this section are not subject to this subpart.

(a) Any unit designated as a stationary combustion turbine, other than an integrated gasification combined cycle (IGCC) unit, covered by 40 CFR part 63, subpart YYYY.

(b) Any electric utility steam generating unit that is not a coal- or oil-fired EGU and combusts natural gas for more than 10.0 percent of the average annual heat input during any 3 calendar years or for more than 15.0 percent of the annual heat input during any calendar year.

(c) Any electric utility steam generating unit that has the capability of combusting more than 25 MW of coal or oil but did not fire coal or oil for more than 10.0 percent of the average annual heat input during any 3 calendar years or for more than 15.0 percent of the

annual heat input during any calendar year. Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and industrial boilers).

(d) Any electric steam generating unit combusting solid waste is a solid waste incineration unit subject to standards established under sections 129 and 111 of the Clean Air Act.

§ 63.9984 When do I have to comply with this subpart?

(a) If you have a new or reconstructed EGU, you must comply with this subpart by April 16, 2012 or upon startup of your EGU, whichever is later, and as further provided for in § 63.10005(g).

(b) If you have an existing EGU, you must comply with this subpart no later than April 16, 2015.

(c) You must meet the notification requirements in § 63.10030 according to the schedule in § 63.10030 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(d) An electric steam generating unit that does not meet the definition of an EGU subject to this subpart on April 16, 2012 for new sources or April 16, 2015 for existing sources must comply with the applicable existing source provisions of this subpart on the date such unit meets the definition of an EGU subject to this subpart.

(e) If you own or operate an electric steam generating unit that is exempted from this subpart under § 63.9983(d), if the manner of operating the unit changes such that the combustion of waste is discontinued and the unit becomes a coal-fired or oil-fired EGU (as defined in § 63.10042), you must be in compliance with this subpart on April 16, 2015 or on the effective date of the switch from waste combustion to coal or oil combustion, whichever is later.

(f) You must demonstrate that compliance has been achieved, by conducting the required performance tests and other activities, no later than 180 days after the applicable date in paragraph (a), (b), (c), (d), or (e) of this section.

§ 63.9985 What is a new EGU?

(a) A new EGU is an EGU that meets any of the criteria specified in paragraph (a)(1) through (a)(2) of this section.

(1) An EGU that commenced construction after May 3, 2011.

(2) An EGU that commenced reconstruction or modification after May 3, 2011.

(b) [Reserved]

Emission Limitations and Work Practice Standards

§ 63.9990 What are the subcategories of EGUs?

(a) Coal-fired EGUs are subcategorized as defined in paragraphs (a)(1) through (a)(2) of this section and as defined in § 63.10042.

(1) EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb, and

(2) EGUs designed for low rank virgin coal.

(b) Oil-fired EGUs are subcategorized as noted in paragraphs (b)(1) through (b)(4) of this section and as defined in § 63.10042.

(1) Continental liquid oil-fired EGUs

(2) Non-continental liquid oil-fired EGUs,

(3) Limited-use liquid oil-fired EGUs, and

(4) EGUs designed to burn solid oil-derived fuel.

(c) IGCC units combusting either gasified coal or gasified solid oil-derived fuel. For purposes of compliance, monitoring, recordkeeping, and reporting requirements in this subpart, IGCC units are subject in the same manner as coal-fired units and solid oil-derived fuel-fired units, unless otherwise indicated.

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Table 1 through 3 to this subpart that applies to your EGU, for each EGU at your source, except as provided under § 63.10009.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your EGU.

(b) As provided in § 63.6(g), the Administrator may approve use of an alternative to the work practice standards in this section.

(c) You may use the alternate SO[2] limit in Tables 1 and 2 to this subpart only if your coal-fired EGU:

(1) Has a system using wet or dry flue gas desulfurization technology and SO[2] continuous emissions monitoring system (CEMS) installed on the unit; and

(2) At all times, you operate the wet or dry flue gas desulfurization technology installed on the unit consistent with § 63.10000(b).

General Compliance Requirements

§ 63.10000 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, you are required to meet the work practice requirements in Table 3 to this subpart during periods of startup or shutdown.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(c)(1) For coal-fired units and solid oil-derived fuel-fired units, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct the initial performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a low emitting EGU (LEE) for one or more applicable emissions limits, with two exceptions:

(A) You may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with an acid gas scrubber and has a main stack and bypass stack exhaust configuration, and

(B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-fired fuel fired EGU or IGCC EGU is new.

(ii) For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status.

(iii) For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(iv) If your coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM

CPMS), a PM CEMS, or compliance performance testing repeated quarterly.

(A) If you elect to use PM CPMS, you will establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the pollutant with which you choose to comply: total non-mercury HAP metals, individual non-mercury HAP metals or filterable PM. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. If you elect to use a PM CPMS, you must repeat the performance test annually for the selected pollutant limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(B) You may also opt to install and operate a particulate matter CEMS certified in accordance with Performance Specification 11 and Procedure 2 of 40 CFR part 60, Appendices B and F, respectively, in accordance with § 63.10010(i).

(v) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), you may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B to this subpart. As an alternative to HCl CEMS, you may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If your EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), you may apply a second alternative to HCl CEMS by installing and operating a sulfur dioxide (SO[2]) CEMS installed and operated in accordance with part 75 of this chapter to demonstrate compliance with the applicable SO[2] emissions limit.

(vi) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for Hg, you must demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with appendix A to this subpart.

(2) For liquid oil-fired EGUs, except limited use liquid oil-fired EGUs, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For an existing liquid oil-fired unit, you may conduct the performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a LEE for one or more pollutants. For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(ii) If your existing liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or performance testing conducted quarterly.

(A) If you elect to use PM CPMS, you will establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the pollutant with which you choose to comply: total HAP metals, individual HAP metals,

or filterable PM. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. If you elect to use a PM CPMS, you must repeat the performance test at least annually for the selected pollutant limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(B) If you elect to use a PM CEMS, you will use the CEMS in accordance with § 63.10010(i) to demonstrate initial and continuous compliance with the filterable PM emission limit.

(iii) If your existing liquid oil-fired unit does not qualify as a LEE for hydrogen chloride (HCl) or for hydrogen fluoride (HF), you may demonstrate initial and continuous compliance through use of an HCl CEMS, an HF CEMS, or an HCl and HF CEMS, installed and operated in accordance with Appendix B to this rule. As an alternative to HCl CEMS, HF CEMS, or HCl and HF CEMS, you may demonstrate initial and continuous compliance by conducting periodic quarterly performance stack tests for HCl and HF. If you elect to demonstrate compliance through quarterly performance testing, then you must also develop a site-specific monitoring plan to ensure that the operations of the unit remain consistent with those during the performance test. As another alternative, you may measure or obtain, and keep records of, fuel moisture content; as long as fuel moisture does not exceed 1.0 percent by weight, you need not conduct other HCl or HF monitoring or testing.

(iv) If your unit qualifies as a limited-use liquid oil-fired as defined in § 63.10042, then you are not subject to the emission limits in Tables 1 and 2, but must comply with the performance tune-up work practice requirements in Table 3.

(d)(1) If you demonstrate compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), you must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation (where applicable) of your CMS. This requirement also applies to you if you petition the Administrator for alternative monitoring parameters under § 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B to part 60 or part 75 of this chapter, and that meet the requirements of § 63.10010. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in your site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs (d)(2) through (5) of this section.

(2) The site-specific monitoring plan shall include the information specified in paragraphs (d)(5)(i) through (d)(5)(vii) of this section. Alternatively, the requirements of paragraphs (d)(5)(i) through (d)(5)(vii) are considered to be met for a particular CMS or sorbent trap monitoring system if:

(i) The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to part 75 of this chapter, or appendix A or B to this subpart; and

(ii) The recordkeeping and reporting requirements of part 75 of this chapter, or appendix A or B to this subpart, that pertain to the CMS are met.

(3) If requested by the Administrator, you must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of § 63.10010 (*e.g.*, if the CMS was previously certified under another program).

(4) You must operate and maintain the CMS according to the site-specific monitoring plan.

(5) The provisions of the site-specific monitoring plan must address the following items:

(i) Installation of the CEMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.*, on or downstream of the last control device). See § 63.10010(a) for further details. For CPMS installations, follow the procedures in § 63.10010(h).

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(iii) Schedule for conducting initial and periodic performance evaluations.

(iv) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations), including ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d).

(v) On-going operation and maintenance procedures, in accordance with the general requirements of §§ 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

(vi) Conditions that define a CMS that is out of control consistent with § 63.8(c)(7)(i) and for responding to out of control periods consistent with §§ 63.8(c)(7)(ii) and (c)(8).

(vii) On-going recordkeeping and reporting procedures, in accordance with the general requirements of §§ 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under this subpart.

(e) As part of your demonstration of continuous compliance, you must perform periodic tune-ups of your EGU(s), according to § 63.10021(e).

(f) You are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (*e.g.*, 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless you are a solid waste incineration unit subject to standards under CAA section 129 (*e.g.*, 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or Subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section

129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

(g) If you no longer meet the definition of an EGU subject to this subpart you must be in compliance with any newly applicable standards on the date you are no longer subject to this subpart. The date you are no longer subject to this subpart is a date selected by you, that must be at least 6 months from the date that you last met the definition of an EGU subject to this subpart or the date you begin combusting solid waste, consistent with § 63.9983(d). Your source must remain in compliance with this subpart until the date you select to cease complying with this subpart or the date you begin combusting solid waste, whichever is earlier.

(h)(1) If you own or operate an EGU that does not meet the definition of an EGU subject to this subpart on April 16, 2015, and you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart, you are subject to the provisions of this subpart, including, but not limited to, the emission limitations and the monitoring requirements, as of the first day you meet the definition of an EGU subject to this subpart. You must complete all initial compliance demonstrations for this subpart applicable to your EGU within 180 days after you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart.

(2) You must provide 30 days prior notice of the date you intend to commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU, the location of the facility, the unit(s) that will commence or recommence operations that will cause the unit(s) to meet the definition of an EGU subject to this subpart, and the date of the notice;

(ii) The 40 CFR part 60, part 62, or part 63 subpart and subcategory currently applicable to your unit(s), and the subcategory of this subpart that will be applicable after you commence or recommence operation that will cause the unit(s) to meet the definition of an EGU subject to this subpart;

(iii) The date on which you became subject to the currently applicable emission limits;

(iv) The date upon which you will commence or recommence operations that will cause your unit to meet the definition of an EGU subject to this subpart, consistent with paragraph (f) of this section.

(i)(1) If you own or operate an EGU subject to this subpart, and it has been at least 6 months since you operated in a manner that caused you to meet the definition of an EGU subject to this subpart, you may, consistent with paragraph (g) of this section, select the date on which your EGU will no longer be subject to this subpart. You must be in compliance with any newly applicable section 112 or 129 standards on the date you selected.

(2) You must provide 30 days prior notice of the date your EGU will cease complying with this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU(s), the location of the facility, the EGU(s) that will cease complying with this subpart, and the date of the notice;

(ii) The currently applicable subcategory under this subpart, and any 40 CFR part 60, part 62, or part 63 subpart and subcategory that will be applicable after you cease complying with this subpart;

(iii) The date on which you became subject to this subpart;

(iv) The date upon which you will cease complying with this subpart, consistent with paragraph (g) of this section.

(j) All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart.

(k) All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart. All calibration and drift checks must be performed as of the date your source ceases to be or becomes subject to this subpart. You must also comply with provisions of §§ 63.10010, 63.10020, and 63.10021 of this subpart. Relative accuracy tests must be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring

requirements or monitoring requirements under this subpart.

§ 63.10001 Affirmative defense for exceedence of emission limit during malfunction.

In response to an action to enforce the standards set forth in § 63.9991 you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at *40 CFR 63.2*. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The excess emissions:

(i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(4) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(b) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction or, if it is not possible to determine within two business days whether the malfunction caused or contributed to an exceedance, no later than two business days after the owner or operator knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in § 63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

Testing and Initial Compliance Requirements

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) *General requirements.* For each of your affected EGUs, you must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing. Where two emissions limits are specified for a particular pollutant (e.g., a heat input-based limit in lb/MMBtu and an electrical output-based limit in lb/MWh), you may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of hourly electrical load data (megawatts); establishment of operating limits according to § 63.10011 and Tables 4 and 7 to this subpart; and CMS performance evaluations. In all cases, you must demonstrate initial compliance no later than the applicable date in paragraph (f) of this section for tune-up work practices for existing EGUs, in § 63.9984 for other requirements for existing EGUs, and in paragraph (g) of this section for all requirements for new EGUs.

(1) To demonstrate initial compliance with an applicable emissions limit in Table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. If you are required to establish operating limits (see paragraph (d) of this section and Table 4 to this subpart), you must collect all applicable parametric data during the performance test period. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period.

(2) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (*i.e.*,

an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO[2] or PM CEMS, the initial performance test consists of 30 boiler operating days of data collected by the initial compliance demonstration date specified in § 63.10005 with the certified monitoring system.

(i) The 30-boiler operating day CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO[2] emissions limit in Table 1 or 2 to this subpart.

(ii) If you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the performance test period.

(b) *Performance testing requirements.* If you choose to use performance testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to § 63.10007 and Table 5 to this subpart. For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in § 63.9984, provided that the following conditions are fully met:

(1) For a performance test based on stack test data, the test was conducted no more than 12 calendar months prior to the date on which compliance is required as specified in § 63.9984;

(2) For a performance test based on data from a certified CEMS or sorbent trap monitoring system, the test consists of all valid data CMS data recorded in the 30 boiler operating days immediately preceding that date;

(3) The performance test was conducted in accordance with all applicable requirements in § 63.10007 and Table 5 to this subpart;

(4) A record of all parameters needed to convert pollutant concentrations to units of the emission standard (e.g., stack flow rate, diluent gas concentrations, hourly electrical loads) is available for the entire performance test period; and

(5) For each performance test based on stack test data, you certify, and keep documentation demonstrating, that the EGU configuration, control devices, and fuel(s) have remained consistent with conditions since the prior performance test was conducted.

(c) *Operating limits.* In accordance with § 63.10010 and Table 4 to this subpart, you may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of your initial compliance demonstration.

(d) *CMS requirements.* If, for a particular emission or operating limit, you are required to (or elect to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of §§ 63.10010(b) through (h), an additional performance evaluation of the CMS is not required under this subpart.

(1) For an affected coal-fired, solid oil-derived fuel-fired, or liquid oil-fired EGU, you may demonstrate initial compliance with the applicable SO[2], HCl, or HF emissions limit in Table 1 or 2 of this subpart through use of an SO[2], HCl, or HF CEMS installed and operated in accordance with part 75 of this chapter or Appendix B to this subpart, as applicable. You may also demonstrate compliance with a filterable PM emission limit in Table 1 or 2 of this subpart through use of a PM CEMS installed, certified, and operated in accordance with § 63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS data, expressed in units of the standard (see § 63.10007(e)), meets the applicable SO[2], PM, HCl, or HF emissions limit in Table 1 or 2 to this subpart. Use Equation 19-19 of Method 19 in appendix A-7 to part 60 of this chapter to calculate the 30-boiler operating day average emissions rate. (Note: for this calculation, the term E[hj] in Equation 19-19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to this subpart).

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the PM CPMS site-specific operating limit that corresponding to the results of the performance test demonstrating compliance with the pollutant with which you choose to comply.

(iii) You must repeat the performance test annually for the selected pollutant emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.

(4) For affected liquid oil-fired EGUs that demonstrate compliance with the applicable emission limits for HCl or HF listed in Table 1 or 2 to this subpart using quarterly testing and continuous monitoring with a CMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984 for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the CMS site-specific operating limit that

corresponding to the results of the performance test demonstrating compliance with the HCl or HF emissions limit.

(iii) You must repeat the performance test annually for the HCl or HF emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(e) *Tune-ups.* All affected EGUs are subject to the work practice standards in Table 3 of this subpart. As part of your initial compliance demonstration, you must conduct a performance tune-up of your EGU according to § 63.10021(e).

(f) For existing affected sources a tune-up may occur prior to April 16, 2012, so that existing sources without neural networks have up to 42 calendar months (3 years from promulgation plus 180 days) or, in the case of units employing neural network combustion controls, up to 54 calendar months (48 months from promulgation plus 180 days) after the date that is specified for your source in § 63.9984 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 9 to this subpart to demonstrate compliance with this requirement. If a tune-up occurs prior to such date, the source must maintain adequate records to show that the tune-up met the requirements of this standard.

(g) If your new or reconstructed affected source commenced construction or reconstruction between May 3, 2011, and July 2, 2011, you must demonstrate initial compliance with either the proposed emission limits or the promulgated emission limits no later than 180 days after April 16, 2012 or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(1) For the new or reconstructed affected source described in this paragraph (g), if you choose to comply with the proposed emission limits when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits within 3 years after April 16, 2012 or within 3 years after startup of the affected source, whichever is later.

(2) If your new or reconstructed affected source commences construction or reconstruction after April 16, 2012, you must demonstrate initial compliance with the promulgated emission limits no later than 180 days after startup of the source.

(h) *Low emitting EGUs.* The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. You may not pursue this compliance option if your existing EGU is equipped with an acid gas scrubber and has a main stack and bypass stack exhaust configuration.

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h), and if those data demonstrate:

(i) For all pollutants except Hg, performance test emissions results less than 50 percent of the applicable emissions limits in Table 1 or 2 to this subpart for all required testing for 3 consecutive years; or

(ii) For Hg emissions from an existing EGU, either:

(A) Average emissions less than 10 percent of the applicable Hg emissions limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh); or

(B) Potential Hg mass emissions of 29.0 or fewer pounds per year and compliance with the applicable Hg emission limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh).

(2) For all pollutants except Hg, you must conduct all required performance tests described in § 63.10007 to demonstrate that a unit qualifies for LEE status.

(i) When conducting emissions testing to demonstrate LEE status, you must increase the minimum sample volume specified in Table 1 or 2 nominally by a factor of two.

(ii) Follow the instructions in § 63.10007(e) and Table 5 to this subpart to convert the test data to the units of the applicable standard.

(3) For Hg, you must conduct a 30-boiler operating day performance test using Method 30B in appendix A-8 to part 60 of this chapter to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within the 10 percent centroidal area of the duct at a location that meets Method 1 in appendix A-1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30-boiler operating day test period. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures), under all process operating conditions. You may use a pair of sorbent traps to sample the stack gas for no more than 10 days.

(i) Depending on whether you intend to assess LEE status for Hg in terms of the lb/TBtu or lb/GWh emission limit in Table 2 to this subpart or in terms of the annual Hg mass emissions limit of 29.0 lb/year, you will have to collect some or all of the following data during the 30-boiler operating day test period (see paragraph (h)(3)(iii) of this section):

(A) Diluent gas (CO[2] or O[2]) data, using either Method 3A in appendix A-3 to part 60 of this chapter or a diluent gas monitor that has been certified according to part 75 of this chapter.

(B) Stack gas flow rate data, using either Method 2, 2F, or 2G in appendices A-1 and A-2 to part 60 of this chapter, or a flow rate monitor that has been certified according to part 75 of this chapter.

(C) Stack gas moisture content data, using either Method 4 in appendix A-1 to part 60 of this chapter, or a moisture monitoring system that has been certified according to part 75 of this chapter. Alternatively, an appropriate fuel-specific default moisture value from § 75.11(b) of this chapter may be used in the calculations or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units.

(D) Hourly electrical load data (megawatts), from facility records.

(ii) If you use CEMS to measure CO[2] (or O[2]) concentration, and/or flow rate, and/or moisture, record hourly average values of each parameter throughout the 30-boiler operating day test period. If you opt to use EPA reference methods rather than CEMS for any parameter, you must perform at least one representative test run on each operating day of the test period, using the applicable reference method.

(iii) Calculate the average Hg concentration, in [mu]g/m<3> (dry basis), for the 30-boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results. Also calculate, as applicable, the average values of CO[2] or O[2] concentration, stack gas flow rate, stack gas moisture content, and electrical load for the test period. Then:

(A) To express the test results in units of lb/TBtu, follow the procedures in § 63.10007(e). Use the average Hg concentration and diluent gas values in the calculations.

(B) To express the test results in units of lb/GWh, use Equations A-3 and A-4 in section 6.2.2 of appendix A to this subpart, replacing the hourly values "C[h] ", "Q[h] ", "B[ws] " and "(MW)[h] " with the average values of these parameters from the performance test.

(C) To calculate pounds of Hg per year, use one of the following methods:

(1) Multiply the average lb/TBtu Hg emission rate (determined according to paragraph (h)(3)(iii)(A) of this section) by the maximum potential annual heat input to the unit (TBtu), which is equal to the maximum rated unit heat input (TBtu/hr) times 8,760 hours. If the maximum rated heat input value is expressed in units of MMBtu/hr, multiply it by 10<6>to convert it to TBtu/hr; or

(2) Multiply the average lb/GWh Hg emission rate (determined according to paragraph (h)(3)(iii)(B) of this section) by the maximum potential annual electricity generation (GWh), which is equal to the maximum rated electrical output of the unit (GW) times 8,760 hours. If the maximum rated electrical output value is expressed in units of MW, multiply it by 10<3> to convert it to GW; or

(3) If an EGU has a federally-enforceable permit limit on either the annual heat input or the number of annual operating hours, you may modify the calculations in paragraph (h)(3)(iii)(C)(1) of this section by replacing the maximum potential annual heat input or 8,760 unit operating hours with the permit limit on annual heat input or operating hours (as applicable).

(4) For a group of affected units that vent to a common stack, you may either assess LEE status for the units individually by performing a separate emission test of each unit in the duct leading from the unit to the common stack, or you may perform a single emission test in the common stack. If you choose the common stack testing option, the units in the configuration qualify for LEE status if:

(i) The emission rate measured at the common stack is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section (with some modifications), are less than or equal to 29.0 pounds times the number of units sharing the common stack. Base your calculations on the combined heat input capacity of all units sharing the stack (i.e., either the combined maximum rated value or, if applicable, a lower combined value restricted by permit conditions or operating hours).

(5) For an affected unit with a multiple stack or duct configuration in which the exhaust stacks or ducts are downstream of all emission control devices, you must

perform a separate emission test in each stack or duct. The unit qualifies for LEE status if:

(i) The emission rate, based on all test runs performed at all of the stacks or ducts, is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section, are less than or equal to 29.0 pounds. Use the average Hg emission rate from paragraph (h)(5)(i) of this section in your calculations.

(i) Liquid-oil fuel moisture measurement. If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraphs (i)(1) through (5) of this section.

(1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or

(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or

(3) Obtain and maintain a fuel moisture certification from your fuel supplier.

(4) Use one of the following methods to determine fuel moisture content:

(i) ASTM D95-05 (Reapproved 2010), "Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation," or

(ii) ASTM D4006-11, "Standard Test Method for Water in Crude Oil by Distillation," including Annex A1 and Appendix A1, or

(iii) ASTM D4177-95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," including Annexes A1 through A6 and Appendices X1 and X2, or

(iv) ASTM D4057-06 (Reapproved 2011), "Standard Practice for Manual Sampling of Petroleum and Petroleum Products," including Annex A1.

(5) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(i) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in § 63.10000(c)(2)(iii) or

(ii) Use an HCl CEMS and/or HF CEMS.

(j) Startup and shutdown for coal-fired or solid oil derived-fired units. You must follow the requirements given in Table 3 to this subpart.

(k) You must submit a Notification of Compliance Status summarizing the results of your initial compliance demonstration, as provided in § 63.10030.

§ 63.10006 When must I conduct subsequent performance tests or tune-ups?

(a) For liquid oil-fired, solid oil-derived fuel- and coal-fired EGUs and IGCC units using PM CPMS to monitor continuous performance with an applicable emission limit as provided for under § 63.10000(c), you must conduct all applicable performance tests according to Table 5 to this subpart and § 63.10007 at least every year.

(b) For affected units meeting the LEE requirements of § 63.10005(h), you must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 and § 63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur:

(1) For all pollutant emission limits except for Hg, you must conduct emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1).

(2) For Hg, you must install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with appendix A to this subpart, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, you must conduct Hg emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1). You must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status.

(c) Except where paragraphs (a) or (b) of this section apply, or where you install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emission limit, for liquid oil-fired EGUs, you must conduct all applicable periodic emissions tests for filterable PM, or individual or total HAP metals emissions according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1).

(d) Except where paragraph (b) of this section applies, for solid oil-derived fuel- and coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO[2] CEMS to

monitor compliance with the alternate equivalent SO[2] emission limit, you must conduct all applicable periodic HCl emissions tests according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1).

(e) Except where paragraph (b) of this section applies, for liquid oil-fired EGUs without HCl CEMS, HF CEMS, or HCl and HF CEMS, you must conduct all applicable emissions tests for HCl, HF, or HCl and HF emissions according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1), and conduct site-specific monitoring under a plan as provided for in § 63.10000(c)(2)(iii).

(f) Unless you follow the requirements listed in paragraphs (g) and (h) of this section, performance tests required at least every 3 calendar years must be completed within 35 to 37 calendar months after the previous performance test; performance tests required at least every year must be completed within 11 to 13 calendar months after the previous performance test; and performance tests required at least quarterly must be completed within 80 to 100 calendar days after the previous performance test, except as otherwise provided in § 63.10021(d)(1).

(g) If you elect to demonstrate compliance using emissions averaging under § 63.10009, you must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (f) of this section.

(h) If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if you choose to reapply for LEE status, you must conduct performance tests at the appropriate

frequency given in section (c) through (e) of this section for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria.

(i) If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to § 63.10021(e).

(1) For EGUs not employing neural network combustion optimization during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 36 calendar months after the previous performance tune-up.

(2) For EGUs employing neural network combustion optimization systems during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 48 calendar months after the previous performance tune-up.

(j) You must report the results of performance tests and performance tune-ups within 60 days after the completion of the performance tests and performance tune-ups. The reports for all subsequent performance tests must include all applicable information required in § 63.10031.

§ 63.10007 What methods and other procedures must I use for the performance tests?

(a) Except as otherwise provided in this section, you must conduct all required performance tests according to § 63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in § 63.7(c).

(1) If you use CEMS (Hg, HCl, SO[2], or other) to determine compliance with a 30-boiler operating day rolling average emission limit, you must collect data

for all nonexempt unit operating conditions (see § 63.10011(g) and Table 3 to this subpart).

(2) If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (*e.g.*, quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non Hg metals emissions limit, operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(b) You must conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to this subpart.

(c) If you choose to comply with the filterable PM emission limit and demonstrate continuous performance using a PM CPMS for an applicable emission limit as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b)(5) and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal

operating load, you must conduct testing at those other loads to determine the additional operating limits.

(d) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, you must conduct a minimum of three separate test runs for each performance test, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 1 or 2 to this subpart. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification.

(e) To use the results of performance testing to determine compliance with the applicable emission limits in Table 1 or 2 to this subpart, proceed as follows:

(1) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (*e.g.*, laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (*e.g.*, analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

(2) If the limits are expressed in lb/MMBtu or lb/TBtu, you must use the F-factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 in appendix A-7 to part 60 of this chapter. In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Use the following factors to convert the pollutant concentrations measured during the initial performance tests to units of lb/scf, for use in the applicable Method 19 equations:

(i) Multiply SO[2] ppm by 1.66 x 10<-7>;

(ii) Multiply HCl ppm by 9.43 x 10<-8>;

(iii) Multiply HF ppm by 5.18 x 10<-8>;

(iv) Multiply HAP metals concentrations (mg/dscm) by 6.24 x 10<-8>; and

(v) Multiply Hg concentrations ([mu]g/scm) by 6.24 x 10<-11>.

(3) To determine compliance with emission limits expressed in lb/MWh or lb/GWh, you must first calculate the pollutant mass emission rate during the performance test, in units of lb/h. For Hg, if a CEMS or sorbent trap monitoring system is used, use Equation A-2 or A-3 in appendix A to this subpart (as applicable). In all other cases, use an equation that has the general form of Equation A-2 or A-3, replacing the value of K with 1.66 x 10<-7> lb/scf-ppm for SO[2], 9.43 x 10<-8> lb/scf-ppm for HCl (if an HCl CEMS is used), 5.18 x 10<-8> lb/scf-ppm for HF (if an HF CEMS is used), or 6.24 x 10<-8> lb-scm/mg-scf for HAP metals and for HCl and HF (when performance stack testing

is used), and defining C[h] as the average SO[2], HCl, or HF concentration in ppm, or the average HAP metals concentration in mg/dscm. This calculation requires stack gas volumetric flow rate (scfh) and (in some cases) moisture content data (see §§ 63.10005(h)(3) and 63.10010). Then, if the applicable emission limit is in units of lb/GWh, use Equation A-4 in appendix A to this subpart to calculate the pollutant emission rate in lb/GWh. In this calculation, define (M)[h] as the calculated pollutant mass emission rate for the performance test (lb/h), and define (MW)[h] as the average electrical load during the performance test (megawatts). If the applicable emission limit is in lb/MWh rather than lb/GWh, omit the 10<3> term from Equation A-4 to determine the pollutant emission rate in lb/MWh.

(f) Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of this section.

§ 63.10008 [Reserved]

§ 63.10009 May I use emissions averaging to comply with this subpart?

(a) *General eligibility.* (1) You may use emissions averaging as described in paragraph (a)(2) of this section as an alternative to meeting the requirements of § 63.9991 for filterable PM, SO[2], HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if:

(i) You have more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control); and

(ii) You use CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance.

(2) You may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the "unit designed for coal >/= 8,300 Btu/lb" subcategory are equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2, according to the procedures in this section. Note that except for Hg emissions from EGUs in the "unit designed for coal >/= 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30 days (rolling daily) using data from CEMS or a combination of data from CEMS and manual performance testing. The averaging time for emissions averaging for Hg from EGUs in the "unit designed for coal >/= 8,300 Btu/lb" subcategory is 90 days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of monitoring data and data from manual performance testing. For the purposes of this paragraph, 30- (or 90-day) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group has operated 30 (or 90) days. You must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) days during the preceding 30 (or 90) group boiler days.

(i) You may choose to have your EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or

gross electrical output basis (MWh or GWh, as appropriate for the pollutant).

(ii) You may not mix bases within your EGU emissions averaging group.

(iii) You may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see paragraph (m) of this section).

(b) *Equations.* Use the following equations when performing calculations for your EGU emissions averaging group:

(1) Group eligibility equations.

$$WAERm = \frac{[\Sigma_{i=1}^{p}(\Sigma_{i=1}^{n}(Herm_i \times Rmm_i)_p] + \Sigma_{i=1}^{m}(Ter_i \times Rmt_i)}{[\Sigma_{i=1}^{p}(\Sigma_{i=1}^{n}Rmm_i)_p] + \Sigma_{i=1}^{m}Rmt_i} \quad (Eq. 1a)$$

Where:

WAERm = Weighted average emissions rate maximum in terms of lb/heat input or lb/gross electrical output,

Herm[i] = Hourly emissions rate (*e.g.*, lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring for hour i,

Rmm[i] = Maximum rated heat input or gross electrical output of unit i in terms of heat input or gross electrical output,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over 30-group boiler operating days,

Ter[i] = Emissions rate from most recent test of unit i in terms of lb/heat input or lb/gross electrical output,

Rmt[i] = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAERm = \frac{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{m}(Herm_i \times Smm_i \times Cfm_i)\right]_p\right] + \sum_{i=1}^{m}(Ter_i \times Smt_i \times Cft_i)}{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{m} Smm_i \times Cfm_i\right]_p\right] + \sum_{i=1}^{m} Smt_i \times Cft_i} \quad (Eq.\ 1b)$$

Where:

variables with similar names share the descriptions for Equation 1a,

Smm[i] = maximum steam generation in units of pounds from unit i that uses CEMS or sorbent trap monitoring,

Cfm[i] = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring,

Smt[i] = maximum steam generation in units of pounds from unit i that uses emissions testing, and

Cft[i] = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing. (2) Weighted 30-day rolling average emissions rate equations for pollutants other than Hg. Use equation 2a or 2b to calculate the 30-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Her_i \times Rm_i)]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Rm_i)]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq.\ 2a)$$

Where:

Her[i] = hourly emission rate (*e.g.*, lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm[i] = hourly heat input or gross electrical output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hourly rates collected over 30-group boiler operating days,

Ter[i] = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt[i] = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cf_i)}{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Sm_i \times Cfm_i)]_p + \sum_{i=1}^{m} St_i \times Cf_i} \quad (Eq.\ 2b)$$

Where:

variables with similar names share the descriptions for Equation 2a,

Sm[i] = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm[i] = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS from the preceding 30-group boiler operating days,

St[i] = steam generation in units of pounds from unit i that uses emissions testing, and

Cft[i] = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing. (3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "unit designed for coal >/= 8,300 Btu/lb" subcategory. Use equation 3a or 3b to calculate the 90-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}[\sum_{i=2}^{n}(Her_i \times Rm_i)]_p + \sum_{i=2}^{m}(Cer_i \times Rt_i)}{\sum_{i=1}^{p}[\sum_{i=2}^{n}(Rm_i)]_p + \sum_{i=2}^{m} Rt_i} \quad (Eq.\ 3a)$$

Where:

Her[i] = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Rm[i] = hourly heat input or gross electrical output from unit i for the preceding 90-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over the 90-group boiler operating days,

Ter[i] = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt[i] = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{n=1}^{n_i}(Ter_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{n=1}^{n_i}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq\ 3b)$$

Where:

variables with similar names share the descriptions for Equation 2a,

Sm[i] = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm[i] = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

St[i] = steam generation in units of pounds from unit i that uses emissions testing, and

Cft[i] = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing. (c) *Separate stack requirements.* For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, you may average filterable PM, SO[2], HF, HCl, non-Hg

HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (d) through (j) of this section.

(d) For each existing EGU in the averaging group:

(1) The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 180 days after April 16, 2015, or the date on which emissions testing done to support your emissions averaging plan is complete (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; or

(2) The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(e) The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified 180 days after April 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier.

(f) Emissions averaging group eligibility demonstration. You must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to

paragraph (f)(1) or (2) of this section using the maximum normal operating load of each EGU and the results of the initial performance tests. For this demonstration and prior to submitting your emissions averaging plan, if requested, you must conduct required emissions monitoring for 30 days of boiler operation and any required manual performance testing to calculate an initial weighted average emissions rate in accordance with this section. Should the Administrator require approval, you must submit your proposed emissions averaging plan and supporting data at least 120 days before April 16, 2015. If the Administrator requires approval of your plan, you may not begin using emissions averaging until the Administrator approves your plan.

(1) You must use Equation 1a in paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO[2], HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 to this subpart.

(2) If you are not capable of monitoring heat input or gross electrical output, and the EGU generates steam for purposes other than generating electricity, you may use Equation 1b of this section as an alternative to using Equation 1a of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO[2], HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 to this subpart.

(g) You must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 day rolling average (90 day rolling

average for Hg) basis according to paragraphs (f)(1) through (3) of this section. The first averaging period begins on 30 (or 90 for Hg) days after February 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross electrical output for each existing unit participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input or gross electrical output, you may use Equation 2b or 3b of paragraph (b) of this section as an alternative to using Equation 2a of paragraph (b) of this section to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

(h) *CEMS (or sorbent trap monitoring) use.* If an EGU in your emissions averaging group uses CEMS (or a sorbent trap monitor for Hg emissions) to demonstrate compliance, you must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate.

(i) *Emissions testing.* If you use manual emissions testing to demonstrate compliance for one or more EGUs in your emissions averaging group, you must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. You may use CEMS or sorbent trap data in combination with data from the most recent manual performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate.

(j) *Emissions averaging plan.* You must develop an implementation plan for emissions averaging

according to the following procedures and requirements in paragraphs (j)(1) and (2) of this section.

(1) You must include the information contained in paragraphs (j)(1)(i) through (v) of this section in your implementation plan for all the emissions units included in an emissions averaging:

(i) The identification of all existing EGUs in the emissions averaging group, including for each either the applicable HAP emission level or the control technology installed as of 180 days after February 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; and the date on which you are requesting emissions averaging to commence;

(ii) The process weighting parameter (heat input, gross electrical output, or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission EGU in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple EGUs, you must identify each EGU;

(iv) The means of measurement (*e.g.*, CEMS, sorbent trap monitoring, manual performance test) of filterable PM, SO[2], HF, HCl, individual or total non-Hg HAP metals, or Hg emissions in accordance with the requirements in § 63.10007 and to be used in the emissions averaging calculations; and

(v) A demonstration that emissions averaging can produce compliance with each of the applicable emission limit(s) in accordance with paragraph (b)(1) of this section.

(2) If the Administrator requests you to submit the plan for review and approval, you must submit a complete implementation plan at least 120 days before April 16, 2015. If the Administrator requests you to submit the plan for review and approval, you must receive approval before initiating emissions averaging.

(i) The Administrator shall use following criteria in reviewing and approving or disapproving the plan:

(A) Whether the content of the plan includes all of the information specified in paragraph (h)(1) of this section; and

(B) Whether the plan presents information sufficient to determine that compliance will be achieved and maintained.

(ii) The Administrator shall not approve an emissions averaging implementation plan containing any of the following provisions:

(A) Any averaging between emissions of different pollutants or between units located at different facilities; or

(B) The inclusion of any emissions unit other than an existing unit in the same subcategory.

(k) *Common stack requirements.* For a group of two or more existing affected units, each of which vents through a single common stack, you may average emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraph (l) or (m) of this section.

(l) For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(m) For all other groups of units subject to paragraph (k) of this section, you may elect to conduct manual performance tests according to procedures specified in § 63.10007 in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (*e.g.*, in a different subcategory) or other nonaffected units all vent to the common stack, you must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, you may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. You may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis.

(n) Combination requirements. The common stack of a group of two or more existing EGUs in the same subcategory subject to paragraph (k) of this section may be treated as a single stack for purposes of paragraph (c) of this section and included in an emissions averaging group subject to paragraph (c) of this section.

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

(1) *Single unit-single stack configurations.* For an affected unit that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

(2) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, you shall either:

(i) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the duct leading to the common stack from each unit; or

(ii) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the common stack.

(3) *Unit(s) utilizing common stack with non-affected unit(s).*

(i) When one or more affected units shares a common stack with one or more non-affected units, you shall either:

(A) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the ducts leading to the common stack from each affected unit; or

(B) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in this section in the common stack and attribute all of the emissions measured at the common stack to the affected unit(s).

(ii) If you choose the common stack monitoring option:

(A) For each hour in which valid data are obtained for all parameters, you must calculate the pollutant emission rate and

(B) You must assign the calculated pollutant emission rate to each unit that shares the common stack.

(4) *Unit with a main stack and a bypass stack.* If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack, or, if it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall install a CEMS only on the main stack and count bypass hours of deviation from the monitoring requirements.

(5) *Unit with a common control device with multiple stack or duct configuration.* If the flue gases from an affected unit, which is configured such that emissions are controlled with a common control device or series of control devices, are discharged to the atmosphere

through more than one stack or are fed into a single stack through two or more ducts, you may:

(i) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the multiple stacks;

(ii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the ducts that feed into the stack;

(iii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in one of the multiple stacks or ducts and monitor the flows and dilution rates in all multiple stacks or ducts in order to determine total exhaust gas flow rate and pollutant mass emissions rate in accordance with the applicable limit; or

(iv) In the case of multiple ducts feeding into a single stack, install CEMS, PM CPMS, and sorbent trap monitoring systems in the single stack as described in paragraph (a)(1) of this section.

(6) *Unit with multiple parallel control devices with multiple stacks.* If the flue gases from an affected unit, which is configured such that emissions are controlled with multiple parallel control devices or multiple series of control devices are discharged to the atmosphere through more than one stack, you shall install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in each of the multiple stacks. You shall calculate hourly flow-weighted average pollutant emission rates for the unit as follows:

(i) Calculate the pollutant emission rate at each stack or duct for each hour in which valid data are obtained for all parameters;

(ii) Multiply each calculated hourly pollutant emission rate at each stack or duct by the corresponding hourly stack gas flow rate at that stack or duct;

(iii) Sum the products determined under paragraph (a)(5)(iii)(B) of this section; and

(iv) Divide the result obtained in paragraph (a)(5)(iii)(C) of this section by the total hourly stack gas flow rate for the unit, summed across all of the stacks or ducts.

(b) If you use an oxygen (O[2]) or carbon dioxide (CO[2]) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O[2] or CO[2] concentrations shall be monitored at a location that represents emissions to the atmosphere, *i.e.*, at the outlet of the EGU, downstream of all emission control devices. You must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O[2] or CO[2] data in the emissions calculations; do not use part 75 substitute data values.

(c) If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.

(d) If you are required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 1 of 2 to this subpart, you must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, for coal-fired units, you may use appropriate fuel-specific default moisture values from § 75.11(b) of this chapter to estimate the moisture content of the stack gas or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units. If you install and operate a moisture monitoring system, do not use substitute moisture data in the emissions calculations.

(e) If you use an HCl and/or HF CEMS, you must install, certify, operate, maintain, and quality-assure the data from the monitoring system in accordance with appendix B to this subpart. Calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of appendix B to this subpart).

(f)(1) If you use an SO[2] CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.

(2) For on-going QA, the SO[2] CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following

addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO[2] CEMS has a span value of 30 ppm or less.

(3) Calculate and record a 30-boiler operating day rolling average SO[2] emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid SO[2] emission rates in the preceding 30 boiler operating days.

(4) Use only unadjusted, quality-assured SO[2] concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO[2] data and do not use part 75 substitute data values.

(g) If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You must calculate and record a 30-boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30 boiler operating days. Section 7.1.4.3 of appendix A to this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit, you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section.

(1) Install, calibrate, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.10000(d), and meet the requirements in paragraphs (h)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal.

(ii) The PM CPMS must have a cycle time (*i.e.*, period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable, at a minimum, of detecting and responding to particulate matter concentrations of 0.5 mg/acm.

(2) For a new unit, complete the initial PM CPMS performance evaluation no later than October 13, 2012 or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than October 13, 2015.

(3) Collect PM CPMS hourly average output data for all boiler operating hours except as indicated in paragraph (h)(5) of this section. Express the PM CPMS output as milliamps, PM concentration, or other raw data signal value.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CPMS output collected during all nonexempt boiler operating

hours data (*e.g.*, milliamps, PM concentration, raw data signal).

(5) You must collect data using the PM CPMS at all times the process unit is operating and at the intervals specified in paragraph (h)(1)(ii) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), and any scheduled maintenance as defined in your site-specific monitoring plan.

(6) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(i) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities conducted during monitoring system malfunctions are not used in calculations (report any such periods in your annual deviation report);

(ii) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods are not used in calculations (report emissions or operating levels and report any such periods in your annual deviation report);

(iii) Any data recorded during periods of startup or shutdown.

(7) You must record and make available upon request results of PM CPMS system performance audits, as well as the dates and duration of periods from when the PM CPMS is out of control until completion of the corrective actions necessary to return the PM CPMS to operation consistent with your site-specific monitoring plan.

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits, you may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (i)(1) through (5) of this section. The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2 to this subpart.

(1) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11--Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using Method 5 at Appendix A-3 to part 60 of this chapter and ensuring that the front half filter temperature shall be 160 [degrees] +/- 14 [degrees] C (320 [degrees] +/- 25 [degrees] F). The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (*e.g.*, lb/MMBtu, lb/MWh).

(2) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2--Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(i) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(ii) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(3) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours.

(5) You must collect data using the PM CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or

control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(ii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(j) You may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with § 63.7(f) as an alternative to the performance test method specified in this rule. If approved to use a HAP metals CEMS, the compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2. If approved, you may choose to install, certify, operate, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in paragraphs (j)(1) through (5) of this section.

(1)(i) Install and certify your HAP metals CEMS according to the procedures and requirements in you approved site specific test plan as required in § 63.7(e). The reportable measurement output from the HAP metals CEMS must be expressed in units of the applicable emissions limit (*e.g.*, lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

(ii) Operate and maintain your HAP metals CEMS according to the procedures and criteria in your site

specific performance evaluation and quality control program plan required in § 63.8(d).

(2) Collect HAP metals CEMS hourly average output data for all boiler operating hours except as indicated in section (j)(4) of this section.

(3) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average HAP metals CEMS output data collected during all nonexempt boiler operating hours data.

(4) You must collect data using the HAP metals CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your emission limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or

operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(ii) You must record and make available upon request results of HAP metals CEMS system performance audits, dates and duration of periods when the HAP metals CEMS is out of control to completion of the corrective actions necessary to return the HAP metals CEMS to operation consistent with your site-specific performance evaluation and quality control program plan.

(k) If you demonstrate compliance with the HCl and HF emission limits for a liquid oil-fired EGU by conducting quarterly testing, you must also develop a site-specific monitoring plan as provided for in § 63.10000(c)(2)(iii) and Table 7 to this subpart.

§ 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

(a) You must demonstrate initial compliance with each emissions limit that applies to you by conducting performance testing.

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance, or if, for a liquid oil-fired unit, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with Table 4 to this

subpart, § 63.10007, and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (*i.e.*, tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit.

(c)(1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (*e.g.*, Hg or HCl) directly, the first 30-boiler operating day rolling average emission rate obtained with certified CEMS after the applicable date in § 63.9984 (or, if applicable, prior to that date, as described in § 63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.

(2) For a unit that uses a CEMS to measure SO[2] or PM emissions for initial compliance, the first 30 boiler operating day average emission rate obtained with certified CEMS after the applicable date in § 63.9984 (or, if applicable, prior to that date, as described in § 63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable SO[2] or filterable PM emission limit in Table 1 or 2 to this subpart.

(d) For candidate LEE units, use the results of the performance testing described in § 63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 1 or 2 to this subpart and to determine whether the unit qualifies for LEE status.

(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, according to § 63.10030(e).

(f)(1) You must determine the fuel whose combustion produces the least uncontrolled emissions, *i.e.*, the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown.

(2) Your cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account.

(g) You must follow the startup or shutdown requirements given in Table 3 for each coal-fired, liquid oil-fired, and solid oil-derived fuel-fired EGU.

Continuous Compliance Requirements

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10000(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during EGU startup or shutdown or monitoring system malfunctions or monitoring system out-of-control

periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

(a) You must demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you, according to the monitoring specified in Tables 6 and 7 to this subpart and paragraphs (b) through (g) of this section.

(b) Except as otherwise provided in § 63.10020(c), if you use a CEMS to measure SO[2], PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO[2],

O[2], or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30-boiler operating day rolling average.

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n} \quad (Eq.\ 8)$$

Where:

Her[i] is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30 boiler operating days.

(c) If you use a PM CPMS data to measure compliance with an operating limit in Table 4 to this subpart, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (*e.g.*, milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 9 to determine the 30 boiler operating day average.

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n} \quad (Eq.\ 9)$$

Where:

Hpv[i] is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30 boiler operating days.

(d) If you use quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 1 or 2 to this subpart, you

(1) May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year.

(2) Must conduct the performance test as defined in Table 5 to this subpart and calculate the results of the testing in units of the applicable emissions standard; and

(3) Must conduct site-specific monitoring for a liquid oil-fired unit to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of § 63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in § 63.10020(a).

(e) If you must conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section, perform the first tune-up as part of your initial compliance demonstration. Notwithstanding this requirement, you may delay the first burner inspection until the next scheduled unit outage provided you meet the requirements of § 63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months.

(1) As applicable, inspect the burner and combustion controls, and clean or replace any components of the

burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

(i) Burner or combustion control component parts needing replacement that affect the ability to optimize NO[X] and CO must be installed within 3 calendar months after the burner inspection,

(ii) Burner or combustion control component parts that do not affect the ability to optimize NO[X] and CO may be installed on a schedule determined by the operator;

(2) As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

(3) As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

(4) As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

(5) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O[2] probes and/or sensors,

adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

(6) Optimize combustion to minimize generation of CO and NO[X]. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO[X] optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

(7) While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO[X] in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NO[X] and O[2] monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;

(8) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including:

(i) The concentrations of CO and NO[X] in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and

(9) Report the dates of the initial and subsequent tune-ups as follows:

(i) If the first required tune-up is performed as part of the initial compliance demonstration, report the date of the tune-up in hard copy (as specified in § 63.10030) and electronically (as specified in § 63.10031). Report the date of each subsequent tune-up electronically (as specified in § 63.10031).

(ii) If the first tune-up is not conducted as part of the initial compliance demonstration, but is postponed until the next unit outage, report the date of that tune-up and all subsequent tune-ups electronically, in accordance with § 63.10031.

(f) You must submit the reports required under § 63.10031 and, if applicable, the reports required under appendices A and B to this subpart. The electronic reports required by appendices A and B to this subpart must be sent to the Administrator electronically in a format prescribed by the

Administrator, as provided in § 63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under § 63.10031.

(g) You must report each instance in which you did not meet an applicable emissions limit or operating limit in Tables 1 through 4 to this subpart or failed to conduct a required tune-up. These instances are deviations from the requirements of this subpart. These deviations must be reported according to § 63.10031.

(h) You must keep records as specified in § 63.10032 during periods of startup and shutdown.

(i) You must provide reports as specified in § 63.10031 concerning activities and periods of startup and shutdown.

§ 63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (3) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.10009(f) and (g);

(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test;

(3) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (3) of this section is a deviation.

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

(a) During the initial performance test or any such subsequent performance test that demonstrates compliance with the filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 1 or 2, record all hourly average output values (*e.g.*, milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (*e.g.*, nine 1-hour

average PM CPMS output values for three 3-hour test runs).

(b) Determine your operating limit as the highest 1-hour average PM CPMS output value recorded during the performance test. You must verify an existing or establish a new operating limit after each repeated performance test.

(c) You must operate and maintain your process and control equipment such that the 30 operating day average PM CPMS output does not exceed the operating limit determined in paragraphs (a) and (b) of this section.

Notification, Reports, and Records

§ 63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after April 16, 2012, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) When you are required to conduct an initial compliance demonstration as specified in § 63.10011(a), you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (7), as applicable.

(1) A description of the affected source(s) including identification of which subcategory the source is in, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under *40 CFR 241.3*, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of *40 CFR 241.3*, and justification for the selection of fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (*e.g.*, use of PM CPMS); CEMS; or a sorbent trap monitoring system.

(4) Identification of whether you plan to demonstrate compliance by emissions averaging.

(5) A signed certification that you have met all applicable emission limits and work practice standards.

(6) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation in the Notification of Compliance Status report.

(7) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following:

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with § 63.10006(i), the date of the last three stack tests, a comparison of the emission level you achieved in the last three stack tests to the 50 percent emission limit threshold required in § 63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(ii) Certifications of compliance, as applicable, and must be signed by a responsible official stating:

(A) "This EGU complies with the requirements in § 63.10021(a) to demonstrate continuous compliance." and

(B) "No secondary materials that are solid waste were combusted in any affected unit."

§ 63.10031 What reports must I submit and when?

(a) You must submit each report in Table 8 to this subpart that applies to you. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also submit the electronic

reports required under appendix A and/or appendix B to the subpart, at the specified frequency.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 8 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.9984 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in § 63.9984.

(2) The first compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.9984.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to *40 CFR 70.6(a)(3)(iii)(A)* or *40 CFR 71.6(a)(3)(iii)(A)*, you may submit the first and

subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (4) of this section.

(1) The information required by the summary report located in 63.10(e)(3)(vi).

(2) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(3) Indicate whether you burned new types of fuel during the reporting period. If you did burn new types of fuel you must include the date of the performance test where that fuel was in use.

(4) Include the date of the most recent tune-up for each unit subject to the requirement to conduct a performance tune-up according to § 63.10021(e). Include the date of the most recent burner inspection if it was not done annually and was delayed until the next scheduled unit shutdown.

(d) For each excess emissions occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in § 63.10(e)(3)(v) in the compliance report specified in section (c).

(e) Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this

chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by *40 CFR 70.6(a)(3)(iii)(A)* or *40 CFR 71.6(a)(3)(iii)(A)*. If an affected source submits a compliance report pursuant to Table 8 to this subpart along with, or as part of, the semiannual monitoring report required by *40 CFR 70.6(a)(3)(iii)(A)* or *40 CFR 71.6(a)(3)(iii)(A)*, and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(f) As of January 1, 2012, and within 60 days after the date of completing each performance test, you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used

electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(1) Within 60 days after the date of completing each CEMS (SO[2], PM, HCl, HF, and Hg) performance evaluation test, as defined in § 63.2 and required by this subpart, you must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). The RATA data shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (*http://www.epa.gov/ttn/chief/ert/index.html*). Only RATA data compounds listed on the ERT Web site are subject to this requirement. Owners or operators who claim that some of the information being submitted for RATAs is confidential business information (CBI) shall submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. The compact disk or other

commonly used electronic storage media shall be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. At the discretion of the delegated authority, owners or operators shall also submit these RATAs to the delegated authority in the format specified by the delegated authority. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in § 63.2 and as required in this chapter.

(2) For a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st, you must submit quarterly reports to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS.

(3) Reports for an SO[2] CEMS, a Hg CEMS or sorbent trap monitoring system, an HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in Appendices A and B to this subpart and § 63.10021(f).

(4) Submit the compliance reports required under paragraphs (c) and (d) of this section and the notification of compliance status required under § 63.10030(e) to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format.

(5) All reports required by this subpart not subject to the requirements in paragraphs (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f)(1), (2), and (3) of this section in paper format.

(g) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.

§ 63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also keep the records required under appendix A and/or appendix B to this subpart.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all

documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in § 63.10(b)(2)(viii).

(b) For each CEMS and CPMS, you must keep records according to paragraphs (b)(1) through (4) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 7 to this subpart including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each EGU subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (3) of this section.

(1) You must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to *40 CFR 241.3(b)(1)*, you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to *40 CFR 241.3(b)(2)*, you must keep records as to how the operations that produced the fuel satisfies the definition of processing in *40 CFR 241.2*. If the fuel received a non-waste determination pursuant to the petition process submitted under *40 CFR 241.3(c)*, you must keep a record which documents how the fuel satisfies the requirements of the petition process.

(3) For an EGU that qualifies as an LEE under § 63.10005(h), you must keep annual records that document that your emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.

(e) If you elect to average emissions consistent with § 63.10009, you must additionally keep a copy of the emissions averaging implementation plan required in § 63.10009(g), all calculations required under § 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.10022.

(f) You must keep records of the occurrence and duration of each startup and/or shutdown.

(g) You must keep records of the occurrence and duration of each malfunction of an operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment.

(h) You must keep records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(i) You must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.

(j) If you elect to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, you must keep records of the type(s) and amount(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met.

§ 63.10033 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§ 63.10040 What parts of the General Provisions apply to me?

Table 9 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.10041 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency; moreover, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate, with respect to any failure by any person to comply with any provision of this subpart.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.9991(a) and (b) under § 63.6(g).

(2) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, approval of minor and

intermediate changes to monitoring performance specifications/procedures in Table 5 where the monitoring serves as the performance test method (see definition of "test method" in § 63.2.

(3) Approval of major changes to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

§ 63.10042 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in § 63.2 (the General Provisions), and in this section as follows:

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Anthracite coal means solid fossil fuel classified as anthracite coal by American Society of Testing and Materials (ASTM) Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Bituminous coal means coal that is classified as bituminous according to ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Boiler operating day means a 24-hour period between midnight and the following midnight during which any fuel is combusted at any time in the steam

generating unit. It is not necessary for the fuel to be combusted the entire 24-hour period.

Capacity factor for a liquid oil-fired EGU means the total annual heat input from oil divided by the product of maximum hourly heat input for the EGU, regardless of fuel, multiplied by 8,760 hours.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (not meeting the definition of natural gas), solvent-refined coal, coal-oil mixtures, and coal-water mixtures, are considered "coal" for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns coal for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Coal refuse means any by-product of coal mining, physical coal cleaning, and coal preparation operations (*e.g.*, culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

Cogeneration means a steam-generating unit that simultaneously produces both electrical and useful

thermal (or mechanical) energy from the same primary energy source.

Cogeneration unit means a stationary, fossil fuel-fired EGU meeting the definition of "fossil fuel-fired" or stationary, integrated gasification combined cycle:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

Combined-cycle gas stationary combustion turbine means a stationary combustion turbine system where

heat from the turbine exhaust gases is recovered by a waste heat boiler.

Common stack means the exhaust of emissions from two or more affected units through a single flue.

Continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located in the continental United States.

Deviation. (1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, work practice standard, or monitoring requirement; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM Method D396-10, "Standard Specification for Fuel Oils" (incorporated by reference, see § 63.14).

Dry flue gas desulfurization technology, or *dry FGD,* or *spray dryer absorber* (*SDA*), or *spray dryer,* or *dry scrubber* means an add-on air pollution control system located downstream of the steam generating unit that

injects a dry alkaline sorbent (dry sorbent injection) or sprays an alkaline sorbent slurry (spray dryer) to react with and neutralize acid gases such as SO[2] and HCl in the exhaust stream forming a dry powder material. Alkaline sorbent injection systems in fluidized bed combustors (FBC) or circulating fluidized bed (CFB) boilers are included in this definition.

Dry sorbent injection (DSI) means an add-on air pollution control system in which sorbent (*e.g.*, conventional activated carbon, brominated activated carbon, Trona, hydrated lime, sodium carbonate, etc.) is injected into the flue gas steam upstream of a PM control device to react with and neutralize acid gases (such as SO[2] and HCl) or Hg in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device.

Electric Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included) for the purpose of powering a generator to produce electricity or electricity and other thermal energy.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Emission limitation means any emissions limit, work practice standard, or operating limit.

Excess emissions means, with respect to this subpart, results of any required measurements outside the applicable range (*e.g.*, emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60, 61, and 63; requirements within any applicable state implementation plan; and any permit requirements established under *40 CFR 52.21* or under 40 CFR 51.18 and 40 CFR 51.24.

Flue gas desulfurization system means any add-on air pollution control system located downstream of the steam generating unit whose purpose or effect is to remove at least 50 percent of the SO[2] in the exhaust gas stream.

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of combusting more than 25 MW of fossil fuels. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (*e.g.*, coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition,

fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, and residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Fluidized bed boiler, or *fluidized bed combustor,* or *circulating fluidized boiler,* or *CFB* means a boiler utilizing a fluidized bed combustion process.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles which are maintained in a mobile suspension by the upward flow of air and combustion products.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, solid oil-derived gas, refinery gas, and biogas.

Generator means a device that produces electricity.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical output, including any such electricity used in the power production process (which process includes, but

is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls), or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in an EGU (synthetic gas for an IGCC) and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, etc.

Integrated gasification combined cycle electric utility steam generating unit or *IGCC* means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year in a combined-cycle gas turbine. No solid coal or solid oil-derived fuel is directly burned in the unit during operation.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite coal means coal that is classified as lignite A or B according to ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Limited-use liquid oil-fired subcategory means an oil-fired electric utility steam generating unit with an

annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing April 16, 2015.

Liquid fuel includes, but is not limited to, distillate oil and residual oil.

Monitoring system malfunction or out of control period means any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 Btu per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Natural gas-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input

during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Non-continental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Non-continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located outside the continental United States.

Non-mercury (Hg) HAP metals means Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se). *Oil* means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, solid oil-derived fuel (*e.g.*, petroleum coke) and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

Oil-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Particulate matter or *PM* means any finely divided solid material as measured by the test methods specified under this subpart, or an alternative method.

Pulverized coal (PC) boiler means an EGU in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the EGU where it is fired in suspension.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by ASTM Method D396-10, "Standard Specification for Fuel Oils" (incorporated by reference, see § 63.14).

Responsible official means responsible official as defined in *40 CFR 70.2*.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use), or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler.

Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use).

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion

turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included).

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit undergrate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. There are two general types of stokers: underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers.

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Unit designed for coal > 8,300 Btu/lb subcategory means any coal-fired EGU that is not a coal-fired EGU

in the "unit designed for low rank virgin coal" subcategory.

Unit designed for low rank virgin coal subcategory means any coal-fired EGU that is designed to burn and that is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed to burn solid oil-derived fuel subcategory means any oil-fired EGU that burns solid oil-derived fuel.

Voluntary consensus standards or VCS mean technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. states, *e.g.*, California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.*, Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within an EPA rule. When this occurs, EPA has done searches

and reviews for VCS equivalent to these non-VCS methods.

Wet flue gas desulfurization technology, or *wet FGD, or wet scrubber* means any add-on air pollution control device that is located downstream of the steam generating unit that mixes an aqueous stream or slurry with the exhaust gases from an EGU to control emissions of PM and/or to absorb and neutralize acid gases, such as SO[2] and HCl.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to CAA section 112(h).

Tables to Subpart UUUUU of Part 63

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
1. Coal-fired unit not low rank	a. Filterable particulate matter	7.0E-3 lb/MWh fn1	Collect a minimum of 4 dscm per run.

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
virgin coal	(PM)		
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GW.	
	Arsenic (As)	3.0E-3 lb/GWh.	
	Beryllium (Be)	6.0E-4 lb/GWh.	
	Cadmium (Cd)	4.0E-4 lb/GWh.	
	Chromium (Cr)	7.0E-3 lb/GWh.	

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Cobalt (Co)	2.0E-3 lb/GWh.	
	Lead (Pb)	2.0E-3 lb/GWh.	
	Manganese (Mn)	4.0E-3 lb/GWh.	
	Nickel (Ni)	4.0E-2 lb/GWh.	
	Selenium (Se)	6.0E-3 lb/GWh.	
	b. Hydrogen chloride (HC1)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 fn2 or Method 320, sample for a

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
			minimum of 1 hour.
	OR.		
	Sulfur dioxide (SO[2]) fn3	4.0E-1 lb/MWh	SO[2] CEMS.
	c. Mercury (Hg)	2.0E-4 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal	a. Filterable particulate matter (PM)	7.0E-3 lb/MWh fn1	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh.	
	Arsenic (As)	3.0E-3 lb/GWh.	
	Beryllium (Be)	6.0E-4 lb/GWh.	
	Cadmium (Cd)	4.0E-4 lb/GWh.	
	Chromium (Cr)	7.0E-3 lb/GWh.	
	Cobalt (Co)	2.0E-3 lb/GWh.	
	Lead (Pb)	2.0E-3 lb/GWh.	
	Manganese (Mn)	4.0E-3 lb/GWh.	
	Nickel (Ni)	4.0E-2 lb/GWh.	

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Selenium (Se)	6.0E-3 lb/GWh.	
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 fn2 or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO[2])< 3>	4.0E-1 lb/MWh	SO[2] CEMS.
	c. Mercury (Hg)	4.0E-2 lb/GWh	Hg CEMS or sorbent trap monitoring

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
3. IGCC unit	a. Filterable particulate matter (PM)	7.0E-2 lb/MWh fn4 9.0E-2 lb/MWh fn5	system only. Collect a minimum of 1 dscm per run.
	OR Total non-Hg HAP metals	OR 4.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E-2 lb/GWh.	
	Arsenic (As)	2.0E-2 lb/GWh.	
	Beryllium (Be)	1.0E-3 lb/GWh.	

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Cadmium (Cd)	2.0E-3 lb/GWh.	
	Chromium (Cr)	4.0E-2 lb/GWh.	
	Cobalt (Co)	4.0E-3 lb/GWh.	
	Lead (Pb)	9.0E-3 lb/GWh.	
	Manganese (Mn)	2.0E-2 lb/GWh.	
	Nickel (Ni)	7.0E-2 lb/GWh.	
	Selenium (Se)	3.0E-1 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26,

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
			collect a minimum of 120 liters per run. For ASTM D6348-03 fn2 or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO[2]) fn3	4.0E-1 lb/MWh	SO fn2 CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-	a. Filterable	7.0E-2 lb/MWh fn1	Collect a minimum

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
fired unit--continental (excluding limited-use liquid oil-fired subcategory units)	particulate matter (PM)		of 1 dscm per run.
	OR Total HAP metals	OR 2.0E-4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E-2 lb/GWh.	
	Arsenic (As)	3.0E-3 lb/GWh.	

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Beryllium (Be)	5.0E-4 lb/GWh.	
	Cadmium (Cd)	2.0E-4 lb/GWh.	
	Chromium (Cr)	2.0E-2 lb/GWh.	
	Cobalt (Co)	3.0E-2 lb/GWh.	
	Lead (Pb)	8.0E-3 lb/GWh.	
	Manganese (Mn)	2.0E-2 lb/GWh.	
	Nickel (Ni)	9.0E-2 lb/GWh.	
	Selenium (Se)	2.0E-2 lb/GWh.	
	Mercury (Hg)	1.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
			concentration should nominally be <1/2 the standard.
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 fn2 or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E-4 lb/MWh	For Method 26A, collect a minimum

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
			of 3 dscm per run. For ASTM D6348-03 fn2 or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit--non-continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	2.0E-1 lb/MWh fn1	Collect a minimum of 1 dscm per run.
	OR Total HAP metals	OR 7.0E-3 lb/MWh	Collect a minimum

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
			of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh.	
	Arsenic (As)	6.0E-2 lb/GWh.	
	Beryllium (Be)	2.0E-3 lb/GWh.	
	Cadmium (Cd)	2.0E-3 lb/GWh.	
	Chromium (Cr)	2.0E-2 lb/GWh.	
	Cobalt (Co)	3.0E-1 lb/GWh.	
	Lead (Pb)	3.0E-2 lb/GWh.	

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Manganese (Mn)	1.0E-1 lb/GWh.	
	Nickel (Ni)	4.1E-0 lb/GWh.	
	Selenium (Se)	2.0E-2 lb/GWh.	
	Mercury (Hg)	4.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
			of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 fn2 or Method 320, sample for a minimum of 1 hour
	c. Hydrogen fluoride (HF)	5.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM)	2.0E-2 lb/MWh fn1	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh.	

fn2 or Method 320, sample for a minimum of 1 hour.

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Arsenic (As)	3.0E-3 lb/GWh.	
	Beryllium (Be)	6.0E-4 lb/GWh.	
	Cadmium (Cd)	7.0E-4 lb/GWh.	
	Chromium (Cr)	6.0E-3 lb/GWh.	
	Cobalt (Co)	2.0E-3 lb/GWh.	
	Lead (Pb)	2.0E-2 lb/GWh.	
	Manganese (Mn)	7.0E-3 lb/GWh.	
	Nickel (Ni)	4.0E-2 lb/GWh.	
	Selenium (Se)	6.0E-3 lb/GWh.	
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum

Table 1 to Subpart UUUUU of Part 63—Emission Limits for new or Reconstructged EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits.]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
			of 3 dscm per run. For ASTM D6348-03 fn2 or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO[2]) fn3	4.0E-1 lb/MWh	SO[2] CEMS.
	c. Mercury (Hg)	2.0E-3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

fn1 Gross electric output.

fn2 Incorporated by reference, see § 63.14.

fn3 You may not use the alternate SO[2] limit if your EGU does not have some form of FGD system and SO[2] CEMS installed.

fn4 Duct burners on syngas; gross electric output.

fn5 Duct burners on natural gas; gross electric output

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh fn2	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals		
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Lead (Pb)	1.2E0 lb/TBtu or	

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
		2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26,

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
			collect a minimum of 120 liters per run. For ASTM D6348-03 fn3 or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO[2]) fn4	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh	SO[2] CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E-2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh2	Collect a minimum of 1 dscm per run.
	Total non-Hg HAP metals OR Individual HAP metals: Antimony (Sb)	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh OR 8.0E-1 lb/TBtu or	Collect a minimum of 1 dscm per run. Collect a minimum of 3 dscm per run.

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
		8.0E-3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh	For Method 26A, collect a minimum of 0.75 dscm per

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
			run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 fn3 or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO[2]) fn4	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh	SO[2] CEMS.
	c. Mercury (Hg)	4.0E0 lb/TBtu or 4.0E-2 lb/GWh	LEE Testing for 30 days with 10 days

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM)	4.0E-2 lb/MMBtu or 4.0E-1 lb/MWh2	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP		Collect a minimum

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	metals:		of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E-2 lb/GWh	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	1.0E-1 lb/TBtu or 1.0E-3 lb/GWh	
	Cadmium (Cd)	1.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E-2 lb/GWh	

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Lead (Pb)	1.9E+2 lb/MMBtu or 1.8E0 lb/MWh	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E-2 lb/GWh	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh	
	b. Hydrogen	5.0E-4 lb/MMBtu or	For Method 26A,

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	chloride (HCl)	5.0E-3 lb/MWh	collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 fn3 or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit--continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh2	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	8.0E-4 lb/MMBtu or 8.0E-3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Individual HAP metals		Collect a minimum of 1 dscm per run.
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E-1 lb/GWh	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Chromium (Cr)	5.5E0 lb/TBtu or	

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
		6.0E-2 lb/GWh	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E-2 lb/GWh	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E-2 lb/GWh	

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 1.0E-2 lb/MWh	For Method 26A, collect a minimum of 1 dscm per Run; for Method 26, collect a minimum

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
			of 120 liters per run. For ASTM D6348-03 fn3 or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E-4 lb/MMBtu or 4.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 fn3 or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit--non-continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh2	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	6.0E-4 lb/MMBtu or 7.0E-3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Individual HAP metals		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E-2 lb/GWh	
	Beryllium (Be)	6.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	3.1E+1 lb/TBtu or	

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
		3.0E-1 lb/GWh	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E-2 lb/GWh	
	Manganese (Mn)	2.0E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E-1 lb/GWh	

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Mercury (Hg)	4.0E-2 lb/TBtu or 4.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.
	Hydrogen chloride (HCl)	2.0E-4 lb/MMBtu or 2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
			of 120 liters per run. For ASTM D6348-03 fn3 or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF)	6.0E-5 lb/MMBtu or 5.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 fn3 or Method 320, sample for a minimum of 2 hours.

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM)	8.0E-3 lb/MMBtu or 9.0E-2 lb/MWh2	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-5 lb/MMBtu or 6.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-1 lb/TBtu or	

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
		5.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-2 lb/TBtu or 6.0E-4 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 4.0E-3 lb/GWh	
	Chromium (Cr)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Lead (Pb)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh	

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E-2 lb/GWh	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E-1 lb/GWh	
	Selenium (Se)	1.2E0 lb/TBtu 2.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	5.0E-3 lb/MMBtu or 8.0E-2 lb/MWh	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run.

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
			For ASTM D6348-03 fn3 or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO[2]) fn4	3.0E-1 lb/MMBtu or 2.0E0 lb/MWh	SO[2] CEMS.
	c. Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or Sorbent trap

Table 2 to Subpart UUUUU of Part 63--Emission Limits for Existing EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] fn1

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 monitoring system only.

fn1 For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.

fn2 Gross electric output.

fn3 Incorporated by reference, see § 63.14.

fn4 You may not use the alternate SO[2] limit if your EGU does not have some form of FGD system and SO[2] CEMS installed.

Table 3 to Subpart UUUUU of Part 63--Work Practice Standards

[As stated in §§ 63.9991, you must comply with the following applicable work practice standards]

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each

Table 3 to Subpart UUUUU of Part 63--Work Practice Standards

[As stated in §§ 63.9991, you must comply with the following applicable work practice standards]

If your EGU is . . .	You must meet the following . . .
	36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
2. A new or reconstructed EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during startup	You must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup

Table 3 to Subpart UUUUU of Part 63--Work Practice Standards

[As stated in §§ 63.9991, you must comply with the following applicable work practice standards]

If your EGU is . . .	You must meet the following . . .
	of a unit, you must use clean fuels,
	either natural gas or distillate oil or a combination of clean fuels for ignition. Once you convert to firing
	coal, residual oil, or solid oil-derived fuel, you must engage all
	of the applicable control technologies
	except dry scrubber and SCR. You must
	start your dry scrubber and SCR systems, if present, appropriately to
	comply with relevant standards applicable during normal operation.
	You must comply with all applicable
	emissions limits at all times except
	for periods that meet the definitions
	of startup and shutdown in this subpart. You must keep records during
	periods of startup. You must provide
	reports concerning activities and periods of startup, as specified in §
	63.10011(g) and § 63.10021(h) and
	(i).

Table 3 to Subpart UUUUU of Part 63--Work Practice Standards

[As stated in §§ 63.9991, you must comply with the following applicable work practice standards]

If your EGU is . . .	You must meet the following . . .
4. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during shutdown	You must operate all CMS during shutdown. Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use) or at the point of no fuel being fired in the boiler. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler. During shutdown, you must operate all applicable control technologies while firing coal, residual oil, or solid oil-derived fuel. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records

Table 3 to Subpart UUUUU of Part 63--Work Practice Standards

[As stated in §§ 63.9991, you must comply with the following applicable work practice standards]

If your EGU is . . .	You must meet the following . . .
during periods of startup. You must	provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).

Table 4 to Subpart UUUUU of Part 63--Operating Limits for EGUs

[As stated in § 63.9991, you must comply with the applicable operating limits]

If you demonstrate compliance using . .	You must meet these operating limits . .
1. PM CPMS	Maintain the 30-boiler operating day rolling average PM CPMS output at or below the highest 1-hour average measured during the most recent performance test demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals

Table 4 to Subpart UUUUU of Part 63--Operating Limits for EGUs

[As stated in § 63.9991, you must comply with the applicable operating limits]

If you demonstrate compliance using . . .	You must meet these operating limits . . .
	including Hg, for liquid oil-fired units) emissions limitation(s).

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . .	Using fn2 . . .
1. Filterable Particulate matter (PM)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . .	Using fn2 . . .
		stack gas	this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. fn3
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the filterable PM concentration	Method 5 at Appendix A-3 to part 60 of this chapter. For positive pressure fabric

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . .	Using fn2 . . .
			filters, Method 5D at Appendix A-3 to part 60 of this chapter for filterable PM emissions. Note that the Method 5 front half temperature shall be 160 [degrees] +/- 14 [degrees] C (320 [degrees] +/- 25 [degrees] F).
		f. Convert emissions concentration to	Method 19 F-factor methodology at Appendix A-7 to

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . .	Using fn2 . . .
		lb/MMBtu or lb/MWh emissions rates	part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR PM CEMS	OR a. Install, certify, operate, and maintain the PM CEMS	Performance Specification 11 at Appendix B to part 60 of this chapter and Procedure 2 at Appendix F to Part 60 of this chapter.
		b. Install,	Part 75 of this

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . .	Using fn2 . . .
		certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit .	Using fn2 . . .
2. Total or individual non-Hg HAP metals	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. fn3

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit .	Using fn2 . . .
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and	Method 29 at Appendix A-8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at Appendix A-8 to

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit .	Using fn2 . . .
		total HAP metals emissions concentration	part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit .	Using fn2 . . .
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . .	Using fn2 . . .
			19.10-1981. fn3
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the HCl and HF emissions concentrations	Method 26 or Method 26A at Appendix A-8 to part 60 of this chapter or Method 320 at Appendix A to part 63 of this chapter or ASTM 6348-03 fn3 with (1) additional

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit .	Using fn2 . . .
			quality assurance measures in footnote fn4 and (2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit. Method 26A must be used if there are entrained water droplets in the exhaust stream.

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . .	Using fn2 . . .
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR HCl and/or HF CEMS	OR a. Install, certify, operate, and maintain the HCl or HF CEMS	Appendix B of this subpart.
		b. Install,	Part 75 of this

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . .	Using fn2 . . .
		certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit .	Using fn2 . . .
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon	Method 3A or 3B at Appendix A-1 to

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit .	Using fn2 . . .
		dioxide concentrations of the stack gas	part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. fn3
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at Appendix A-8 to part 60 of this chapter, ASTM D6784 fn3, or Method 29 at Appendix A-8 to part 60 of this chapter; for Method 29, you

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit .	Using fn2 . . .
		.	must report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR Hg CEMS	Sections 3.2.1 and

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit .	Using fn2 . . .
		a. Install, certify, operate, and maintain the CEMS	5.1 of Appendix A of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day	Section 6 of Appendix A to this subpart.

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . .	Using fn2 . . .
		rolling average lb/TBtu or lb/GWh emissions rates	
	OR	OR	
	Sorbent trap monitoring system	a. Install, certify, operate, and maintain the sorbent trap monitoring system	Sections 3.2.2 and 5.2 of Appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . .	Using fn2 . . .
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of Appendix A to this subpart.
	OR LEE testing	OR a. Select sampling ports location and the number of traverse points	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at Appendix A-1 to

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit .	Using fn2 . . .
			part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G, or 2H at Appendix A-1 or A-2 to part 60 of this chapter or flow monitoring system certified per Appendix A of this subpart.

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . .	Using fn2 . . .
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981, fn3 or diluent gas monitoring systems certified according to Part 75 of this chapter.
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter, or

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . .	Using fn2 . . .
			moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at Appendix A-8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (i.e., per pair of sorbent

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using fn2 . . .
			traps) or sorbent trap monitoring system or Hg CEMS certified per Appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . .	Using fn2 . . .
			data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 22.0 lb/year threshold	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.
5. Sulfur dioxide (SO[2])	SO[2] CEMS	a. Install, certify, operate, and maintain the CEMS	Part 75 of this chapter and §§ 63.10010(a) and (f).
		b. Install, operate, and	Part 75 of this chapter and §§

Table 5 to Subpart UUUUU of Part 63--Performance Testing Requirements

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources fn1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . .	Using fn2 . . .
		maintain the diluent gas, flow rate, and/or moisture monitoring systems	63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).

fn1 Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and § 63.10021(h).

fn2 See Tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.

fn3 Incorporated by reference, see § 63.14.

fn4 When using ASTM D6348-03, the following conditions must be met: (1) The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory; (2) For ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5); (3) For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be 70% >/= R </= 130%; and (4) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

$$Reported\ Result = \frac{(Measured\ Concentration\ in\ Stack)}{\%R} \times 100$$

Table 6 to Subpart UUUUU of Part 63--Establishing PM CPMS Operating Limits

[As stated in § 63.10007, you must comply with the following requirements for establishing operating limits]

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
Particulate matter (PM), total non-mercury HAP metals,	Install, certify, maintain, and operate a PM CPMS for	Establish a site-specific operating limit in units of PM CPMS	Data from the PM CPMS and the PM or HAP metals performance	1. Collect PM CPMS output data during the entire period of the

Table 6 to Subpart UUUUU of Part 63--Establishing PM CPMS Operating Limits

[As stated in § 63.10007, you must comply with the following requirements for establishing operating limits]

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
individual non-mercury HAP metals, total HAP metals, individual HAP metals	monitoring emissions discharged to the atmosphere according to § 63.10010(g)(1)	output signal (e.g., milliamps, mg/acm, or other raw signal)	tests	performance tests. 2. Record the average hourly PM CPMS output for each test run in the three run performance test. 3. Determine the highest 1-hour average PM CPMS measured during the performance test demonstrating compliance

Table 6 to Subpart UUUUU of Part 63--Establishing PM CPMS Operating Limits

[As stated in § 63.10007, you must comply with the following requirements for establishing operating limits]

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
				with the filterable PM or HAP metals emissions limitations.

Table 7 to Subpart UUUUU of Part 63--Demonstrating Continuous Compliance

[As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following]

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg	Calculating the 30-boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day

Table 7 to Subpart UUUUU of Part 63--Demonstrating Continuous Compliance

[As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following]

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
	using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30 boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit	Calculating the arithmetic 30-boiler operating day rolling average of all of the quality assured hourly average PM CPMS output data (e.g., milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30 boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring for liquid oil-fired units for HCl and HF	If applicable, by conducting the monitoring in accordance with an

Table 7 to Subpart UUUUU of Part 63--Demonstrating Continuous Compliance

[As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following]

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
emission limit monitoring	approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired units to measure compliance with one or more applicable emissions limit in Table 1 or 2	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid	Operating in accordance with Table 3.

Table 7 to Subpart UUUUU of Part 63--Demonstrating Continuous Compliance

[As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following]

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
oil-derived fuel-fired EGUs during shutdown	

Table 8 to Subpart UUUUU of Part 63--Reporting Requirements

[As stated in § 63.10031, you must comply with the following requirements for reports]

You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.10031(c)(1) through (4); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in	Semiannually according to the requirements in § 63.10031(b).

Table 8 to Subpart UUUUU of Part 63--Reporting Requirements

[As stated in § 63.10031, you must comply with the following requirements for reports]

You must submit a . . .	The report must contain . . .	You must submit the report . . .
	Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and	

Table 8 to Subpart UUUUU of Part 63--Reporting Requirements

[As stated in § 63.10031, you must comply with the following requirements for reports]

You must submit a . . .	The report must contain . . .	You must submit the report . . .
	c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.10031(e)	

Table 9 to Subpart UUUUU of Part 63--Applicability of General Provisions to Subpart UUUUU

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	Yes.
§ 63.6(a), (b)(1)-(b)(5), (b)(7), (c), (f)(2)-(3), (g), (h)(2)-(h)(9), (i), (j)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.10000(b) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.7(a), (b), (c), (d), (e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.

Table 9 to Subpart UUUUU of Part 63--Applicability of General Provisions to Subpart UUUUU

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
§ 63.7(e)(1)	Performance testing	No. See § 63.10007.
§ 63.8	Monitoring Requirements	Yes.
63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See § 63.10000(b) for general duty requirement.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1), (c), (d)(1)-(2), (e), and (f)	Recordkeeping and Reporting Requirements	Yes, except for the requirements to submit written reports under § 63.10(e)(3)(v).
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See 63.10001 for recordkeeping of (1)

Table 9 to Subpart UUUUU of Part 63--Applicability of General Provisions to Subpart UUUUU

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
		occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii)-(ix)	Other CMS requirements	Yes.
§ 63.10(b)(3), and (d)(3)-(5)		No.
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS--identifying exceedances and excess emissions	Yes.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS--identifying exceedances and excess	Yes.

Table 9 to Subpart UUUUU of Part 63--Applicability of General Provisions to Subpart UUUUU

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
	emissions	
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See 63.10021(h) and (i) for malfunction reporting requirements.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§ 63.1(a)(5), (a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3),	Reserved	No.

Table 9 to Subpart UUUUU of Part 63--Applicability of General Provisions to Subpart UUUUU

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
(h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9)		

Appendix A to Subpart UUUUU--Hg Monitoring Provisions

1. General Provisions

1.1 *Applicability.* These monitoring provisions apply to the measurement of total vapor phase mercury (Hg) in emissions from electric utility steam generating units, using either a mercury continuous emission monitoring system (Hg CEMS) or a sorbent trap monitoring system. The Hg CEMS or sorbent trap monitoring system must be capable of measuring the total vapor phase mercury in units of the applicable emissions standard (*e.g.*, lb/TBtu or lb/GWh), regardless of speciation.

1.2 *Initial Certification and Recertification Procedures.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall comply with the initial certification and recertification procedures in section 4 of this appendix.

1.3 *Quality Assurance and Quality Control Requirements.* The owner or operator of an affected

unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall meet the applicable quality assurance requirements in section 5 of this appendix.

1.4 *Missing Data Procedures.* The owner or operator of an affected unit is not required to substitute for missing data from Hg CEMS or sorbent trap monitoring systems. Any process operating hour for which quality-assured Hg concentration data are not obtained is counted as an hour of monitoring system downtime.

2. Monitoring of Hg Emissions

2.1 *Monitoring System Installation Requirements.* Flue gases from the affected units under this subpart vent to the atmosphere through a variety of exhaust configurations including single stacks, common stack configurations, and multiple stack configurations. For each of these configurations, § 63.10010(a) specifies the appropriate location(s) at which to install continuous monitoring systems (CMS). These CMS installation provisions apply to the Hg CEMS, sorbent trap monitoring systems, and other continuous monitoring systems that provide data for the Hg emissions calculations in section 6.2 of this appendix.

2.2 *Primary and Backup Monitoring Systems.* In the electronic monitoring plan described in section 7.1.1.2.1 of this appendix, you must designate a primary Hg CEMS or sorbent trap monitoring system. The primary system must be used to report hourly Hg concentration values when the system is able to provide quality-assured data, *i.e.,* when the system is "in control". However, to increase data availability in

the event of a primary monitoring system outage, you may install, operate, maintain, and calibrate backup monitoring systems, as follows:

2.2.1 *Redundant Backup Systems.* A redundant backup monitoring system may be either a separate Hg CEMS with its own probe, sample interface, and analyzer, or a separate sorbent trap monitoring system. A redundant backup system is one that is permanently installed at the unit or stack location, and is kept on "hot standby" in case the primary monitoring system is unable to provide quality-assured data. A redundant backup system must be represented as a unique monitoring system in the electronic monitoring plan. Each redundant backup monitoring system must be certified according to the applicable provisions in section 4 of this appendix and must meet the applicable on-going QA requirements in section 5 of this appendix.

2.2.2 *Non-redundant Backup Monitoring Systems.* A non-redundant backup monitoring system is a separate Hg CEMS or sorbent trap system that has been certified at a particular unit or stack location, but is not permanently installed at that location. Rather, the system is kept on "cold standby" and may be reinstalled in the event of a primary monitoring system outage. A non-redundant backup monitoring system must be represented as a unique monitoring system in the electronic monitoring plan. Non-redundant backup Hg CEMS must complete the same certification tests as the primary monitoring system, with one exception. The 7-day calibration error test is not required for a non-redundant backup Hg CEMS. Except as otherwise provided in section 2.2.4.5 of this appendix, a non-redundant backup monitoring system

may only be used for 720 hours per year at a particular unit or stack location.

2.2.3 *Temporary Like-kind Replacement Analyzers.* When a primary Hg analyzer needs repair or maintenance, you may temporarily install a like-kind replacement analyzer, to minimize data loss. Except as otherwise provided in section 2.2.4.5 of this appendix, a temporary like-kind replacement analyzer may only be used for 720 hours per year at a particular unit or stack location. The analyzer must be represented as a component of the primary Hg CEMS, and must be assigned a 3-character component ID number, beginning with the prefix "LK".

2.2.4 *Quality Assurance Requirements for Non-redundant Backup Monitoring Systems and Temporary Like-kind Replacement Analyzers.* To quality-assure the data from non-redundant backup Hg monitoring systems and temporary like-kind replacement Hg analyzers, the following provisions apply:

2.2.4.1 When a certified non-redundant backup sorbent trap monitoring system is brought into service, you must follow the procedures for routine day-to-day operation of the system, in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

2.2.4.2 When a certified non-redundant backup Hg CEMS or a temporary like-kind replacement Hg analyzer is brought into service, a calibration error test and a linearity check must be performed and passed. A single point system integrity check is also required, unless a NIST-traceable source of oxidized Hg was used for the calibration error test.

2.2.4.3 Each non-redundant backup Hg CEMS or temporary like-kind replacement Hg analyzer shall comply with all required daily, weekly, and quarterly quality-assurance test requirements in section 5 of this appendix, for as long as the system or analyzer remains in service.

2.2.4.4 For the routine, on-going quality-assurance of a non-redundant backup Hg monitoring system, a relative accuracy test audit (RATA) must be performed and passed at least once every 8 calendar quarters at the unit or stack location(s) where the system will be used.

2.2.4.5 To use a non-redundant backup Hg monitoring system or a temporary like-kind replacement analyzer for more than 720 hours per year at a particular unit or stack location, a RATA must first be performed and passed at that location.

3. Mercury Emissions Measurement Methods

The following definitions, equipment specifications, procedures, and performance criteria are applicable to the measurement of vapor-phase Hg emissions from electric utility steam generating units, under relatively low-dust conditions (i.e., sampling in the stack or duct after all pollution control devices). The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents the sum of elemental Hg (Hg<0,> CAS Number 7439-97-6) and oxidized forms of Hg.

3.1 *Definitions.*

3.1.1 *Mercury Continuous Emission Monitoring System or Hg CEMS* means all of the equipment used to continuously determine the total vapor phase Hg concentration. The measurement system may include

the following major subsystems: sample acquisition, Hg<+2> to Hg<0> converter, sample transport, sample conditioning, flow control/gas manifold, gas analyzer, and data acquisition and handling system (DAHS). Hg CEMS may be nominally real-time or time-integrated, batch sampling systems that sample the gas on an intermittent basis and concentrate on a collection medium before intermittent analysis and reporting.

3.1.2 *Sorbent Trap Monitoring System* means the equipment required to monitor Hg emissions continuously by using paired sorbent traps containing iodated charcoal (IC) or other suitable sorbent medium. The monitoring system consists of a probe, paired sorbent traps, an umbilical line, moisture removal components, an airtight sample pump, a gas flow meter, and an automated data acquisition and handling system. The system samples the stack gas at a constant proportional rate relative to the stack gas volumetric flow rate. The sampling is a batch process. The average Hg concentration in the stack gas for the sampling period is determined, in units of micrograms per dry standard cubic meter ([mu]g/dscm), based on the sample volume measured by the gas flow meter and the mass of Hg collected in the sorbent traps.

3.1.3 *NIST* means the National Institute of Standards and Technology, located in Gaithersburg, Maryland.

3.1.4 *NIST-Traceable Elemental Hg Standards* means either: compressed gas cylinders having known concentrations of elemental Hg, which have been prepared according to the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards"; or calibration gases having known concentrations of elemental Hg, produced by a

generator that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators" or an interim version of that protocol.

3.1.5 *NIST-Traceable Source of Oxidized Hg* means a generator that is capable of providing known concentrations of vapor phase mercuric chloride ($HgCl_2$), and that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators" or an interim version of that protocol.

3.1.6 *Calibration Gas* means a NIST-traceable gas standard containing a known concentration of elemental or oxidized Hg that is produced and certified in accordance with an EPA traceability protocol.

3.1.7 *Span Value* means a conservatively high estimate of the Hg concentrations to be measured by a CEMS. The span value of a Hg CEMS should be set to approximately twice the concentration corresponding to the emission standard, rounded off as appropriate (see section 3.2.1.4.2 of this appendix).

3.1.8 *Zero-Level Gas* means calibration gas containing a Hg concentration that is below the level detectable by the Hg gas analyzer in use.

3.1.9 *Low-Level Gas* means calibration gas with a concentration that is 20 to 30 percent of the span value.

3.1.10 *Mid-Level Gas* means calibration gas with a concentration that is 50 to 60 percent of the span value.

3.1.11 *High-Level Gas* means calibration gas with a concentration that is 80 to 100 percent of the span value.

3.1.12 *Calibration Error Test* means a test designed to assess the ability of a Hg CEMS to measure the concentrations of calibration gases accurately. A zero-level gas and an upscale gas are required for this test. For the upscale gas, either a mid-level gas or a high-level gas may be used, and the gas may either be an elemental or oxidized Hg standard.

3.1.13 *Linearity Check* means a test designed to determine whether the response of a Hg analyzer is linear across its measurement range. Three elemental Hg calibration gas standards (i.e., low, mid, and high-level gases) are required for this test.

3.1.14 *System Integrity Check* means a test designed to assess the transport and measurement of oxidized Hg by a Hg CEMS. Oxidized Hg standards are used for this test. For a three-level system integrity check, low, mid, and high-level calibration gases are required. For a single-level check, either a mid-level gas or a high-level gas may be used.

3.1.15 *Cycle Time Test* means a test designed to measure the amount of time it takes for a Hg CEMS, while operating normally, to respond to a known step change in gas concentration. For this test, a zero gas and a high-level gas are required. The high-level gas may be either an elemental or an oxidized Hg standard.

3.1.16 *Relative Accuracy Test Audit* or *RATA* means a series of nine or more test runs, directly comparing readings from a Hg CEMS or sorbent trap monitoring system to measurements made with a reference stack test method. The relative accuracy (RA) of the monitoring system is expressed as the absolute mean difference between the monitoring system and reference method measurements plus the absolute

value of the 2.5 percent error confidence coefficient, divided by the mean value of the reference method measurements.

3.1.17 *Unit Operating Hour* means a clock hour in which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.1.18 *Stack Operating Hour* means a clock hour in which gases flow through a particular monitored stack or duct (either for part of the hour or for the entire hour), while the associated unit(s) are combusting fuel.

3.1.19 *Operating Day* means a calendar day in which a source combusts any fuel.

3.1.20 Quality Assurance *(QA) Operating Quarter* means a calendar quarter in which there are at least 168 unit or stack operating hours (as defined in this section).

3.1.21 *Grace Period* means a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

3.2 *Continuous Monitoring Methods.*

3.2.1 *Hg CEMS.* A typical Hg CEMS is shown in Figure A-1. The CEMS in Figure A-1 is a dilution extractive system, which measures Hg concentration on a wet basis, and is the most commonly-used type of Hg CEMS. Other system designs may be used, provided that the CEMS meets the performance specifications in section 4.1.1 of this appendix.

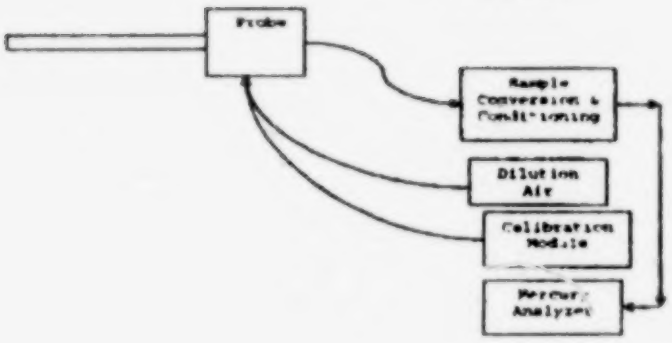

FIGURE A-1. TYPICAL MERCURY CEMS

3.2.1.1 Equipment Specifications.

3.2.1.1.1 Materials of Construction. All wetted sampling system components, including probe components prior to the point at which the calibration gas is introduced, must be chemically inert to all Hg species. Materials such as perfluoroalkoxy (PFA) Teflon<TM>, quartz, and treated stainless steel (SS) are examples of such materials.

3.2.1.1.2 Temperature Considerations. All system components prior to the Hg+2 to Hg<0> converter must be maintained at a sample temperature above the acid gas dew point.

3.2.1.1.3 Measurement System Components.

3.2.1.1.3.1 Sample Probe. The probe must be made of the appropriate materials as noted in paragraph 3.2.1.1.1 of this section, heated when necessary, as described in paragraph 3.2.1.1.3.4 of this section, and configured with ports for introduction of calibration gases.

3.2.1.1.3.2 Filter or Other Particulate Removal Device. The filter or other particulate removal device is part of the measurement system, must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section, and must be included in all system tests.

3.2.1.1.3.3 Sample Line. The sample line that connects the probe to the converter, conditioning system, and analyzer must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section.

3.2.1.1.3.4 Conditioning Equipment. For wet basis systems, such as the one shown in Figure A-1, the sample must be kept above its dew point either by: heating the sample line and all sample transport components up to the inlet of the analyzer (and, for hot-wet extractive systems, also heating the analyzer); or diluting the sample prior to analysis using a dilution probe system. The components required for these operations are considered to be conditioning equipment. For dry basis measurements, a condenser, dryer or other suitable device is required to remove moisture continuously from the sample gas, and any equipment needed to heat the probe or sample line to avoid condensation prior to the moisture removal component is also required.

3.2.1.1.3.5 *Sampling Pump.* A pump is needed to push or pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. If a mechanical sample pump is used and its surfaces are in contact with the sample gas prior to detection, the pump must be leak free and must be constructed of a material that is non-reactive to the gas being sampled (see paragraph 3.2.1.1.1 of this section). For dilution-type measurement systems, such as the system shown in Figure A-1, an ejector pump (eductor) may be used to create a sufficient vacuum that sample gas will be drawn through a critical orifice at a constant rate. The ejector pump must be constructed of any material that is non-reactive to the gas being sampled.

3.2.1.1.3.6 *Calibration Gas System(s).* Design and equip each Hg CEMS to permit the introduction of known concentrations of elemental Hg and HgCl[2] separately, at a point preceding the sample extraction filtration system, such that the entire measurement system can be checked. The calibration gas system(s) must be designed so that the flow rate exceeds the sampling system flow requirements and that the gas is delivered to the CEMS at atmospheric pressure.

3.2.1.1.3.7 *Sample Gas Delivery.* The sample line may feed directly to either a converter, a by-pass valve (for Hg speciating systems), or a sample manifold. All valve and/or manifold components must be made of material that is non-reactive to the gas sampled and the calibration gas, and must be configured to safely discharge any excess gas.

3.2.1.1.3.8 *Hg Analyzer.* An instrument is required that continuously measures the total vapor phase Hg concentration in the gas stream. The analyzer may also be capable of measuring elemental and oxidized Hg separately.

3.2.1.1.3.9 *Data Recorder.* A recorder, such as a computerized data acquisition and handling system (DAHS), digital recorder, or data logger, is required for recording measurement data.

3.2.1.2 *Reagents and Standards.*

3.2.1.2.1 *NIST Traceability.* Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this section) shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg<0> and HgCl[2] are required. Special reagents and equipment may be needed to prepare the Hg<0> and HgCl[2] gas

standards (*e.g.*, NIST-traceable solutions of HgCl[2] and gas generators equipped with mass flow controllers).

3.2.1.2.2 *Required Calibration Gas Concentrations.*

3.2.1.2.2.1 *Zero-Level Gas.* A zero-level calibration gas with a Hg concentration below the level detectable by the Hg analyzer is required for calibration error tests and cycle time tests of the CEMS.

3.2.1.2.2.2 *Low-Level Gas.* A low-level calibration gas with a Hg concentration of 20 to 30 percent of the span value is required for linearity checks and 3-level system integrity checks of the CEMS. Elemental Hg standards are required for the linearity checks and oxidized Hg standards are required for the system integrity checks.

3.2.1.2.2.3 *Mid-Level Gas.* A mid-level calibration gas with a Hg concentration of 50 to 60 percent of the span value is required for linearity checks and for 3-level system integrity checks of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error tests.

3.2.1.2.2.4 *High-Level Gas.* A high-level calibration gas with a Hg concentration of 80 to 100 percent of the span value is required for linearity checks, 3-level system integrity checks, and cycle time tests of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg

standards may be used for the calibration error and cycle time tests.

3.2.1.3 *Installation and Measurement Location.* For the Hg CEMS and any additional monitoring system(s) needed to convert Hg concentrations to the desired units of measure (i.e., a flow monitor, CO[2] or O[2] monitor, and/or moisture monitor, as applicable), install each monitoring system at a location: that is consistent with 63.10010(a); that represents the emissions exiting to the atmosphere; and where it is likely that the CEMS can pass the relative accuracy test.

3.2.1.4 *Monitor Span and Range Requirements.* Determine the appropriate span and range value(s) for the Hg CEMS as described in paragraphs 3.2.1.4.1 through 3.2.1.4.3 of this section.

3.2.1.4.1 *Maximum Potential Concentration.* There are three options for determining the maximum potential Hg concentration (MPC). Option 1 applies to coal combustion. You may use a default value of 10 [mu]g/scm for all coal ranks (including coal refuse) except for lignite; for lignite, use 16 [mu]g/scm. If different coals are blended as part of normal operation, use the highest MPC for any fuel in the blend. Option 2 is to base the MPC on the results of site-specific Hg emission testing. This option may be used only if the unit does not have add-on Hg emission controls or a flue gas desulfurization system, or if testing is performed upstream of all emission control devices. If Option 2 is selected, perform at least three test runs at the normal operating load, and the highest Hg concentration obtained in any of the tests shall be the MPC. Option 3 is to use fuel sampling and analysis to estimate the MPC. To make this estimate, use the average Hg content (*i.e.*, the weight percentage) from

at least three representative fuel samples, together with other available information, including, but not limited to the maximum fuel feed rate, the heating value of the fuel, and an appropriate F-factor. Assume that all of the Hg in the fuel is emitted to the atmosphere as vapor-phase Hg.

3.2.1.4.2 *Span Value.* To determine the span value of the Hg CEMS, multiply the Hg concentration corresponding to the applicable emissions standard by two. If the result of this calculation is an exact multiple of 10 [mu]g/scm, use the result as the span value. Otherwise, round off the result to either: the next highest integer; the next highest multiple of 5 [mu]g/scm; or the next highest multiple of 10 [mu]g/scm.

3.2.1.4.3 *Analyzer Range.* The Hg analyzer must be capable of reading Hg concentration as high as the MPC.

3.2.2 *Sorbent Trap Monitoring System.* A sorbent trap monitoring system (as defined in paragraph 3.1.2 of this section) may be used as an alternative to a Hg CEMS. If this option is selected, the monitoring system shall be installed, maintained, and operated in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. The system shall be certified in accordance with the provisions of section 4.1.2 of this appendix.

3.2.3 *Other Necessary Data Collection.* To convert measured hourly Hg concentrations to the units of the applicable emissions standard (*i.e.,* lb/TBtu or lb/GWh), additional data must be collected, as described in paragraphs 3.2.3.1 through 3.2.3.3 of this section. Any additional monitoring systems needed for this purpose must be certified, operated, maintained,

and quality-assured according to the applicable provisions of part 75 of this chapter (see §§ 63.10010(b) through (d)). The calculation methods for the types of emission limits described in paragraphs 3.2.3.1 and 3.2.3.2 of this section are presented in section 6.2 of this appendix.

3.2.3.1 *Heat Input-Based Emission Limits.* For a heat input-based Hg emission limit (*i.e.*, in lb/TBtu), data from a certified CO[2] or O[2] monitor are needed, along with a fuel-specific F-factor and a conversion constant to convert measured Hg concentration values to the units of the standard. In some cases, the stack gas moisture content must also be considered in making these conversions.

3.2.3.2 *Electrical Output-Based Emission Rates.* If the applicable Hg limit is electrical output-based (*i.e.*, lb/GWh), hourly electrical load data and unit operating times are required in addition to hourly data from a certified stack gas flow rate monitor and (if applicable) moisture data.

3.2.3.3 *Sorbent Trap Monitoring System Operation.* Routine operation of a sorbent trap monitoring system requires the use of a certified stack gas flow rate monitor, to maintain an established ratio of stack gas flow rate to sample flow rate.

4. Certification and Recertification Requirements

4.1 *Certification Requirements.* All Hg CEMS and sorbent trap monitoring systems and the additional monitoring systems used to continuously measure Hg emissions in units of the applicable emissions standard in accordance with this appendix must be certified in a timely manner, such that the initial

compliance demonstration is completed no later than the applicable date in § 63.10005(g).

4.1.1 *Hg CEMS.* Table A-1, below, summarizes the certification test requirements and performance specifications for a Hg CEMS. The CEMS may not be used to report quality-assured data until these performance criteria are met. Paragraphs 4.1.1.1 through 4.1.1.5 of this section provide specific instructions for the required tests. All tests must be performed with the affected unit(s) operating (*i.e.*, combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the certification tests.

4.1.1.1 *7-Day Calibration Error Test.* Perform the 7-day calibration error test on 7 consecutive source operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in sections 3.1.8, 3.1.10, and 3.1.11 of this appendix). Either elemental or oxidized NIST-traceable Hg standards (as defined in sections 3.1.4 and 3.1.5 of this appendix) may be used for the test. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate the Hg CEMS in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over nonconsecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the

monitor (*i.e.*, resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined, and use only the unadjusted analyzer responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A-1. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A-1.

4.1.1.2 *Linearity Check.* Perform the linearity check using low, mid, and high-level concentrations of NIST-traceable elemental Hg standards. Three gas injections at each concentration level are required, with no two successive injections at the same concentration level. Introduce the calibration gas at the gas injection port, as specified in section 3.2.1.1.3.6 of this appendix. Operate the CEMS at its normal operating temperature and conditions. Pass the calibration gas through all filters, scrubbers, conditioners, and other components used during normal sampling, and through as much of the sampling probe as is practical. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Record the monitor response from the data acquisition and handling system for each gas injection. At each concentration level, use the average analyzer response to calculate the linearity error (LE), as described in Table A-1. The LE must either meet the main performance specification or the alternative specification in Table A-1.

4.1.1.3 *Three-Level System Integrity Check.* Perform the 3-level system integrity check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as described in Table A-1. The SIE must either meet the main performance specification or the alternative specification in Table A-1. (**Note:** This test is not required if the CEMS does not have a converter).

Table A-1--Required Certification Tests and Performance Specifications for Hg CEMS

For this required certification test . . .	The main performance specification fn1 is . . .	The alternate performance specification fn1 is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test fn2	:R - A : </=5.0% of span value, for both the zero and upscale gases, on each of the 7 days	:R - A : </=1.0 [mu]g/scm	The alternate specification may be used on any day of the test.
Linearity check fn3	:R - A[avg] : </=10.0% of the	:R - A[avg] : </=0.8 [mu]g/scm	The alternate specification may

Table A-1--Required Certification Tests and Performance Specifications for Hg CEMS

For this required certification test . . .	The main performance specification fn1 is . . .	The alternate performance specification fn1 is . . .	And the conditions of the alternate specification are . . .
	reference gas concentration at each calibration gas level (low, mid, or high)		be used at any gas level.
3-level system integrity check fn4	:R - A[avg] : </=10.0% of the reference gas concentration at each calibration gas level	:R - A[avg] : </=0.8 [mu]g/scm	The alternate specification may be used at any gas level.
RATA	20.0% RA	:RM[avg] - C[avg] : </=1.0 [mu]g/scm * *	RM[avg] <5.0 [mu]g/scm.
Cycle time test fn2	15 minutes. fn5		

fn1 Note that :R - A : is the absolute value of the difference between the reference gas value and the analyzer reading. :R - A[avg], : is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.

fn2 Use either elemental or oxidized Hg standards; a mid-level or high-level upscale gas may be used. This test is not required for Hg CEMS that use integrated batch sampling; however, those monitors must be capable of recording at least one Hg concentration reading every 15 minutes.

fn3 Use elemental Hg standards.

fn4 Use oxidized Hg standards. Not required if the CEMS does not have a converter.

fn5 Stability criteria--Readings change by <2.0% of span or by </=0.5 [mu]g/scm, for 2 minutes.

* * Note that :RM[avg] -C[avg] : is the absolute difference between the mean reference method value and the mean CEMS value from the RATA. The arithmetic difference between RM[avg] and C[avg] can be either + or -.

4.1.1.4 *Cycle Time Test.* Perform the cycle time test, using a zero-level gas and a high-level calibration gas.

Either an elemental or oxidized NIST-traceable Hg standard may be used as the high-level gas. Perform the test in two stages--upscale and downscale. The slower of the upscale and downscale response times is the cycle time for the CEMS. Begin each stage of the test by injecting calibration gas after achieving a stable reading of the stack emissions. The cycle time is the amount of time it takes for the analyzer to register a reading that is 95 percent of the way between the stable stack emissions reading and the final, stable reading of the calibration gas concentration. Use the following criterion to determine when a stable reading of stack emissions or calibration gas has been attained--the reading is stable if it changes by no more than 2.0 percent of the span value or 0.5 [mu]g/scm (whichever is less restrictive) for two minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Integrated batch sampling type Hg CEMS are exempted from this test; however, these systems

must be capable of delivering a measured Hg concentration reading at least once every 15 minutes. If necessary to increase measurement sensitivity of a batch sampling type Hg CEMS for a specific application, you may petition the Administrator for approval of a time longer than 15 minutes between readings.

4.1.1.5 *Relative Accuracy Test Audit (RATA).* Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784-02 (Reapproved 2008), "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)" (incorporated by reference, see § 63.14) and Methods 29, 30A, and 30B in appendix A-8 to part 60. When Method 29 or ASTM D6784-02 is used, paired sampling trains are required. To validate a Method 29 or ASTM D6784-02 test run, calculate the relative deviation (RD) using Equation A-1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 [mu]g/dscm. If the average concentration is </= 1.0 [mu]g/dscm, the RD must not exceed 20 percent. The RD results are also acceptable if the absolute difference between the two Hg concentrations does not exceed 0.2 [mu]g/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

$$RD = \frac{|C_a - C_b|}{C_a + C_b} \times 100 \quad \text{(Eq. A-1)}$$

Where:

RD = Relative deviation between the Hg concentrations of samples "a" and "b" (percent)

C[a] = Hg concentration of Hg sample "a" ([mu]g/dscm)

C[b] = Hg concentration of Hg sample "b" ([mu]g/dscm)

4.1.1.5.1 Special Considerations. A minimum of nine valid test runs must be performed, directly comparing the CEMS measurements to the reference method. More than nine test runs may be performed. If this option is chosen, the results from a maximum of three test runs may be rejected so long as the total number of test results used to determine the relative accuracy is greater than or equal to nine; however, all data must be reported including the rejected data. The minimum time per run is 21 minutes if Method 30A is used. If Method 29, Method 30B, or ASTM D6784-02 (Reapproved 2008), "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)" (incorporated by reference, see § 63.14) is used, the time per run must be long enough to collect a sufficient mass of Hg to analyze. Complete the RATA within 168 unit operating hours, except when Method 29 or ASTM D6784-02 is used, in which case up to 336 operating hours may be taken to finish the test.

4.1.1.5.2 Calculation of RATA Results. Calculate the relative accuracy (RA) of the monitoring system, on a [mu]g/scm basis, as described in section 12 of Performance Specification (PS) 2 in Appendix B to part 60 of this chapter (see Equations 2-3 through 2-6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry. The CEMS must either meet the main performance specification or the alternative specification in Table A-1.

4.1.1.5.3 Bias Adjustment. Measurement or adjustment of Hg CEMS data for bias is not required.

4.1.2 *Sorbent Trap Monitoring Systems.* For the initial certification of a sorbent trap monitoring system, only a RATA is required.

4.1.2.1 *Reference Methods.* The acceptable reference methods for the RATA of a sorbent trap monitoring system are the same as those listed in paragraph 4.1.1.5 of this section.

4.1.2.2 "The special considerations specified in paragraph 4.1.1.5.1 of this section apply to the RATA of a sorbent trap monitoring system. During the RATA, the monitoring system must be operated and quality-assured in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter with the following exceptions for sorbent trap section 2 breakthrough:

4.1.2.2.1 For stack Hg concentrations >1 [mu]g/dscm, </=10% of section 1 Hg mass;

4.1.2.2.2 For stack Hg concentrations </=1 [mu]g/dscm and >0.5 [mu]g/dscm, </= 20% of section 1 Hg mass;

4.1.2.2.3 For stack Hg concentrations </=0.5 [mu]g/dscm and >0.1 [mu]g/dscm, </= 50% of section 1 Hg mass; and

4.1.2.2.4 For stack Hg concentrations </=0.1[mu]g/dscm, no breakthrough criterion assuming all other QA/QC specifications are met.

4.1.2.3 The type of sorbent material used by the traps during the RATA must be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

4.1.2.4 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the sorbent trap monitoring system, on a [mu]g/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2-3 through 2-6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry.The main and alternative RATA performance specifications in Table A-1 for Hg CEMS also apply to the sorbent trap monitoring system.

4.1.2.5 *Bias Adjustment.* Measurement or adjustment of sorbent trap monitoring system data for bias is not required.

4.1.3 *Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems.* Monitoring systems that are used to measure stack gas volumetric flow rate, diluent gas concentration, or stack gas moisture content, either for routine operation of a sorbent trap monitoring system or to convert Hg concentration data to units of the applicable emission limit, must be certified in accordance with the applicable provisions of part 75 of this chapter.

4.2 *Recertification.* Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS or sorbent trap monitoring system that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the

concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. Ongoing Quality Assurance (QA) and Data Validation

5.1 Hg CEMS.

5.1.1 Required QA Tests. Periodic QA testing of each Hg CEMS is required following initial certification. The required QA tests, the test frequencies, and the performance specifications that must be met are summarized in Table A-2, below. All tests must be performed with the affected unit(s) operating (i.e., combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the tests. For each test, follow the same basic procedures in section 4.1.1 of this appendix that were used for initial certification.

5.1.2 Test Frequency. The frequency for the required QA tests of the Hg CEMS shall be as follows:

5.1.2.1 Calibration error tests of the Hg CEMS are required daily, except during unit outages. Use either NIST-traceable elemental Hg standards or NIST-traceable oxidized Hg standards for these calibrations. Both a zero-level gas and either a mid-level or high-level gas are required for these calibrations.

5.1.2.2 Perform a linearity check of the Hg CEMS in each QA operating quarter, using low-level, mid-level,

and high-level NIST-traceable elemental Hg standards. For units that operate infrequently, limited exemptions from this test are allowed for "non-QA operating quarters". A maximum of three consecutive exemptions for this reason are permitted, following the quarter of the last test. After the third consecutive exemption, a linearity check must be performed in the next calendar quarter or within a grace period of 168 unit or stack operating hours after the end of that quarter. The test frequency for 3-level system integrity checks (if performed in lieu of linearity checks) is the same as for the linearity checks. Use low-level, mid-level, and high-level NIST-traceable oxidized Hg standards for the system integrity checks.

5.1.2.3 If required, perform a single-level system integrity check weekly, *i.e.*, once every 7 operating days (see the third column in Table A-2).

5.1.2.4 The test frequency for the RATAs of the Hg CEMS shall be annual, *i.e.*, once every four QA operating quarters. For units that operate infrequently, extensions of RATA deadlines are allowed for non-QA operating quarters. Following a RATA, if there is a subsequent non-QA quarter, it extends the deadline for the next test by one calendar quarter. However, there is a limit to these extensions; the deadline may not be extended beyond the end of the eighth calendar quarter after the quarter of the last test. At that point, a RATA must either be performed within the eighth calendar quarter or in a 720 hour unit or stack operating hour grace period following that quarter. When a required annual RATA is done within a grace period, the deadline for the next RATA is three QA operating quarters after the quarter in which the grace period test is performed.

5.1.3 *Grace Periods.*

5.1.3.*1 A 168* unit or stack operating hour grace period is available for quarterly linearity checks and 3-level system integrity checks of the Hg CEMS.

5.1.3.*2 A 720* unit or stack operating hour grace period is available for RATAs of the Hg CEMS.

5.1.3.3 There is no grace period for weekly system integrity checks. The test must be completed once every 7 operating days.

5.1.4 *Data Validation.* The Hg CEMS is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any one of the acceptance criteria for the required QA tests in Table A-2 is not met. The CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.1.5 *Conditional Data Validation.* For certification, recertification, and diagnostic testing of Hg monitoring systems, and for the required QA tests when non-redundant backup Hg monitoring systems or temporary like-kind Hg analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete 7-day calibration error tests, linearity checks, cycle time tests, and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter. Required system integrity checks must be completed within 168 unit or stack operating hours after the probationary calibration error test.

Table A-2--On-Going QA Test Requirements for Hg CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Calibration error test	Daily	. Use either a mid- or high-level gas . Use either elemental or oxidized Hg . Calibrations are not required when the unit is not in operation	:R-A : </= 5.0% of span value. or :R-A : </= 1.0 [mu]g/scm.
Single-level system integrity check	Weekly fn1	. Required only for systems with converters . Use oxidized Hg– either mid- or high-level . Not required if daily calibrations are done with a NIST-traceable source of oxidized	:R-A[avg] : </= 10.0% of the reference gas value. or :R-A[avg] : </= 0.8 [mu]g/scm.

Table A-2--On-Going QA Test Requirements for Hg CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Linearity check or 3-level system integrity check	Quarterly fn3	. Required in each "QA operating quarter" fn2 -- and no less than once every 4 calendar quarters . 168 operating hour grace period available . Use elemental Hg for linearity check . Use oxidized Hg for system integrity check . For system integrity check, CEMS must have a converter	:R-A[avg] : </= 10.0% of the reference gas value, at each calibration gas level. or :R-A[avg] : </= 0.8 [mu]g/scm.
RATA	Annual fn4	. Test deadline may be extended for	20.0% RA. or

Table A-2--On-Going QA Test Requirements for Hg CEMS

Perform this type of QA test . . .	At this frequency . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
		"non-QA operating quarters", up to a maximum of 8 quarters from the quarter of the previous test . 720 operating hour grace period available	:RM[avg] - C[avg] : </= 1.0 [mu]g/scm, if RM[avg] < 5.0 [mu]g/scm.

fn1 "Weekly" means once every 7 operating days.

fn2 A "QA operating quarter" is a calendar quarter with at least 168 unit or stack operating hours.

fn3 "Quarterly" means once every QA operating quarter.

fn4 "Annual" means once every four QA operating quarters.

5.1.6 *Adjustment of Span.* If you discover that a span adjustment is needed (*e.g.*, if the Hg concentration readings exceed the span value for a significant percentage of the unit operating hours in a calendar quarter), you must implement the span adjustment within 90 days after the end of the calendar quarter in which you identify the need for the adjustment. A diagnostic linearity check is required within 168 unit or stack operating hours after changing the span value.

5.2 *Sorbent Trap Monitoring Systems.*

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B-1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.2.2 For ongoing QA, periodic RATAs of the system are required.

5.2.2.1 The RATA frequency shall be annual, i.e., once every four QA operating quarters. The provisions in section 5.1.2.4 of this appendix pertaining to RATA deadline extensions also apply to sorbent trap monitoring systems.

5.2.2.2 The same RATA performance criteria specified in Table A-4 for Hg CEMS shall apply to the annual RATAs of the sorbent trap monitoring system.

5.2.2.3 A 720 unit or stack operating hour grace period is available for RATAs of the monitoring system.

5.2.3 Data validation for sorbent trap monitoring systems shall be done in accordance with Table 12B-1 in Performance Specification (PS) 12B in appendix B to part 60 of this chapter. All periods of invalid data shall be counted as hours of monitoring system downtime.

5.3 *Flow Rate, Diluent Gas, and Moisture Monitoring Systems.* The on-going QA test requirements for these monitoring systems are specified in part 75 of this chapter (see §§ 63.10010(b) through (d)).

5.4 *QA/QC Program Requirements.* The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the Hg CEMS and/or sorbent trap monitoring systems that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the diluent gas, flow rate, and moisture monitoring systems described in section 3.2.1.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

5.4.1 *General Requirements.*

5.4.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the Hg CEMS and/or sorbent trap monitoring system(s) in proper operating condition and a schedule for those procedures. Include, at a minimum, all procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

5.4.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

5.4.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any Hg CEMS or sorbent trap monitoring system in a location and format suitable for inspection. A

maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded (*e.g.*, changing the dilution ratio of a CEMS), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

5.4.2 *Specific Requirements for Hg CEMS.*

5.4.2.1 *Daily Calibrations, Linearity Checks and System Integrity Checks.* Keep a written record of the procedures used for daily calibrations of the Hg CEMS. If moisture and/or chlorine is added to the Hg calibration gas, document how the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration is accounted for in an appropriate manner. Also keep records of the procedures used to perform linearity checks of the Hg CEMS and the procedures for system integrity checks of the Hg CEMS. Document how the test results are calculated and evaluated.

5.4.2.2 *Monitoring System Adjustments.* Document how each component of the Hg CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

5.4.2.3 *Relative Accuracy Test Audits.* Keep a written record of procedures used for RATAs of the Hg CEMS. Indicate the reference methods used and document how the test results are calculated and evaluated.

5.4.3 *Specific Requirements for Sorbent Trap Monitoring Systems.*

5.4.3.1 *Sorbent Trap Identification and Tracking.* Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for chain of custody purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg collection period.

5.4.3.2 *Monitoring System Integrity and Data Quality.* Document the procedures used to perform the leak checks when a sorbent trap is placed in service and removed from service. Also Document the other QA procedures used to ensure system integrity and data quality, including, but not limited to, gas flow meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in Table 12B-1 in section 9.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. All reference meters used to calibrate the gas flow meters (*e.g.*, wet test meters) shall be periodically recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST-traceable calibration device is used as a reference flow meter, the QA plan must include a protocol for ongoing maintenance and periodic recalibration to maintain the accuracy and NIST-traceability of the calibrator.

5.4.3.3 *Hg Analysis.* Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps. Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 11.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter.

5.4.3.4 *Data Collection Period.* State, and provide the rationale for, the minimum acceptable data collection period (*e.g.,* one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Address such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.4.3.5 *Relative Accuracy Test Audit Procedures.* Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

6. Data Reduction and Calculations

6.1 Data Reduction.

6.1.1 Reduce the data from Hg CEMS to hourly averages, in accordance with § 60.13(h)(2) of this chapter.

6.1.2 For sorbent trap monitoring systems, determine the Hg concentration for each data collection period and assign this concentration value to each operating hour in the data collection period.

6.1.3 For any operating hour in which valid data are not obtained, either for Hg concentration or for a parameter used in the emissions calculations (*i.e.,* flow rate, diluent gas concentration, or moisture, as applicable), do not calculate the Hg emission rate for that hour. For the purposes of this appendix, part 75 substitute data values are not considered to be valid data.

6.1.4 Operating hours in which valid data are not obtained for Hg concentration are considered to be

hours of monitor downtime. The use of substitute data for Hg concentration is not required.

6.2 *Calculation of Hg Emission Rates.* Use the applicable calculation methods in paragraphs 6.2.1 and 6.2.2 of this section to convert Hg concentration values to the appropriate units of the emission standard.

6.2.1 *Heat Input-Based Hg Emission Rates.* Calculate hourly heat input-based Hg emission rates, in units of lb/TBtu, according to sections 6.2.1.1 through 6.2.1.4 of this appendix.

6.2.1.1 Select an appropriate emission rate equation from among Equations 19-1 through 19-9 in EPA Method 19 in appendix A-7 to part 60 of this chapter.

6.2.1.2 Calculate the Hg emission rate in lb/MMBtu, using the equation selected from Method 19. Multiply the Hg concentration value by 6.24 x 10<-11> to convert it from [mu]g/scm to lb/scf. In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Also, for startup and shutdown hours, you may calculate the Hg emission rate using the applicable diluent cap value specified in section 3.3.4.1 of appendix F to part 75 of this chapter, provided that the diluent gas monitor is not out-of-control and the hourly average O[2] concentration is above 14.0% O[2] (19.0% for an IGCC) or the hourly average CO[2] concentration is below 5.0% CO[2] (1.0% for an IGCC), as applicable.

6.2.1.3 Multiply the lb/MMBtu value obtained in section 6.2.1.2 of this appendix by 10<6> to convert it to lb/TBtu.

6.2.1.4 The heat input-based Hg emission rate limit in Table 2 to this subpart must be met on a 30 boiler operating day rolling average basis. Use Equation 19-19 in EPA Method 19 to calculate the Hg emission rate for each averaging period. The term E[hj] in Equation 19-19 must be in the units of the applicable emission limit. Do not include non-operating hours with zero emissions in the average.

6.2.2 *Electrical Output-Based Hg Emission Rates.* Calculate electrical output-based Hg emission limits in units of lb/GWh, according to sections 6.2.2.1 through 6.2.2.3 of this appendix.

6.2.2.1 Calculate the Hg mass emissions for each operating hour in which valid data are obtained for all parameters, using Equation A-2 of this section (for wet-basis measurements of Hg concentration) or Equation A-3 of this section (for dry-basis measurements), as applicable:

$$M_h = K C_h Q_h \qquad \text{(Equation A-2)}$$

Where:

M[h] = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24 x 10<-11> lb-scm/[mu]g-scf,

C[h] = Hourly average Hg concentration, wet basis ([mu]g/scm)

Q[h] = Stack gas volumetric flow rate for the hour (scfh).

(**Note:** Use unadjusted flow rate values; bias adjustment is not required)

$$M_h = K C_h Q_h (1 - B_{ws}) \qquad \text{(Equation A-3)}$$

Where:
M[h] = Hg mass emission rate for the hour (lb/h)
K = Units conversion constant, 6.24 x 10<-11> lb-scm/[mu]g-scf.
C[h] = Hourly average Hg concentration, dry basis ([mu]g/dscm).
Q[h] = Stack gas volumetric flow rate for the hour (scfh)
(**Note:** Use unadjusted flow rate values; bias adjustment is not required).
B[ws] = Moisture fraction of the stack gas, expressed as a decimal (equal to % H[2] O/100)

6.2.2.2 Use Equation A-4 of this section to calculate the emission rate for each unit or stack operating hour in which valid data are obtained for all parameters.

$$E_{ho} = \frac{M_h}{(MW)_h} x\,10^3 \qquad \text{(Equation A-4)}$$

Where:
E[ho] = Electrical output-based Hg emission rate (lb/GWh).
M[h] = Hg mass emission rate for the hour, from Equation A-2 or A-3 of this section, as applicable (lb/h).
(MW)[h] = Gross electrical load for the hour, in megawatts (MW).
10 <3> = Conversion factor from megawatts to gigawatts.

6.2.2.3 The applicable electrical output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30-boiler operating day rolling average basis. Use Equation A-5 of this section to calculate the Hg emission rate for each averaging period.

$$\overline{E}_o = \frac{\sum_{h=1}^{n} E_{ho}}{n}$$ (Equation A-5)

Where:

E [o] = Hg emission rate for the averaging period (lb/GWh).

E[ho] = Electrical output-based hourly Hg emission rate for unit or stack operating hour "h" in the averaging period, from Equation A-4 of this section (lb/GWh).

n = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters

(**Note:** Do *not* include non-operating hours with zero emission rates in the average).

7. Recordkeeping and Reporting

7.1 *Recordkeeping Provisions.* For the Hg CEMS and/or sorbent trap monitoring systems and any other necessary monitoring systems installed at each affected unit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 7.1.1 through 7.1.10 of this section.

7.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the Hg CEMS and/or sorbent trap monitoring system(s) and any other monitoring system(s) (*i.e.,* flow rate, diluent gas, or moisture systems) needed for routine operation of a sorbent trap monitoring system or to convert Hg concentrations to units of the applicable emission standard. The

monitoring plan shall contain essential information on the continuous monitoring systems and shall Document how the data derived from these systems ensure that all Hg emissions from the unit or stack are monitored and reported.

7.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (*e.g.*, a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

7.1.1.2 *Contents of the Monitoring Plan.* For Hg CEMS and sorbent trap monitoring systems, the monitoring plan shall contain the information in sections 7.1.1.2.1 and 7.1.1.2.2 of this appendix, as applicable. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the information required for those systems under § 75.53 (g) of this chapter.

7.1.1.2.1 *Electronic.* The electronic monitoring plan records must include the following: unit or stack ID number(s); monitoring location(s); the Hg monitoring methodologies used; Hg monitoring system information, including, but not limited to: Unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate Hg emissions; Hg monitor span and range information The electronic monitoring plan shall be evaluated and submitted using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool

provided by the Clean Air Markets Division in the Office of Atmospheric Programs of the EPA.

7.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the Hg monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations; miscellaneous technical justifications.

7.1.2 *Operating Parameter Records.* The owner or operator shall record the following information for each operating hour of each affected unit and also for each group of units utilizing a common stack, to the extent that these data are needed to convert Hg concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 7.1.2.1 and 7.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 7.1.2.1, 7.1.2.2, and (if applicable) 7.1.2.4 of this section.

7.1.2.1 The date and hour;

7.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

7.1.2.3 The hourly gross unit load (rounded to nearest MWe); and

7.1.2.4 If applicable, the F-factor used to calculate the heat input-based Hg emission rate.

7.1.3 *Hg Emissions Records (Hg CEMS).* For each affected unit or common stack using a Hg CEMS, the owner or operator shall record the following information for each unit or stack operating hour:

7.1.3.1 The date and hour;

7.1.3.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the CEMS provides a quality-assured value of Hg concentration for the hour;

7.1.3.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour ([mu]g/scm, rounded to three significant figures);

7.1.3.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour. This code may be entered manually when a temporary like-kind replacement Hg analyzer is used for reporting; and

7.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

7.1.4 *Hg Emissions Records (Sorbent Trap Monitoring Systems).* For each affected unit or common stack using a sorbent trap monitoring system, each owner or operator shall record the following information for the unit or stack operating hour in each data collection period:

7.1.4.1 The date and hour;

7.1.4.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the sorbent trap system provides a quality-assured value of Hg concentration for the hour;

7.1.4.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour ([mu]g/scm, rounded to three significant figures). Note that when a quality-assured Hg concentration value is obtained for a particular data collection period, that single concentration value is applied to each operating hour of the data collection period.

7.1.4.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour;

7.1.4.5 The average flow rate of stack gas through each sorbent trap (in appropriate units, *e.g.*, liters/min, cc/min, dscm/min);

7.1.4.6 The gas flow meter reading (in dscm, rounded to the nearest hundredth), at the beginning and end of the collection period and at least once in each unit operating hour during the collection period;

7.1.4.7 The ratio of the stack gas flow rate to the sample flow rate, as described in section 12.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter; and

7.1.4.8 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

7.1.5 *Stack Gas Volumetric Flow Rate Records.*

7.1.5.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required for routine operation of sorbent trap monitoring systems, to maintain the required ratio of stack gas flow rate to sample flow rate (see section 8.2.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter). Hourly stack gas flow rate data are also needed in order to demonstrate compliance with electrical output-based Hg emissions limits, as provided in section 6.2.2 of this appendix.

7.1.5.2 For each affected unit or common stack, if hourly measurements of stack gas flow rate are needed for sorbent trap monitoring system operation or to convert Hg concentrations to the units of the

emission standard, use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

7.1.6 *Records of Stack Gas Moisture Content.*

7.1.6.1 Correction of hourly Hg concentration data for moisture is sometimes required when converting Hg concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

7.1.6.1.1 For sorbent trap monitoring systems;

7.1.6.1.2 For Hg CEMS that measure Hg concentration on a dry basis, when you must calculate electrical output-based Hg emission rates; and

7.1.6.1.3 When using certain equations from EPA Method 19 in appendix A-7 to part 60 of this chapter to calculate heat input-based Hg emission rates.

7.1.6.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage from § 75.11(b)(1) of this chapter or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

7.1.7 *Records of Diluent Gas (CO*[2] or O[2]) Concentration.

7.1.7.1 When a heat input-based Hg mass emissions limit must be met, in units of lb/TBtu, hourly measurements of CO[2] or O[2] concentration are required to convert Hg concentrations to units of the standard.

7.1.7.2 If hourly measurements of diluent gas concentration are needed, use a certified CO[2] or O[2] monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly CO[2] or O[2] concentration records, as specified in § 75.57(g) of this chapter.

7.1.8 *Hg Emission Rate Records.* For applicable Hg emission limits in units of lb/TBtu or lb/GWh, record the following information for each affected unit or common stack:

7.1.8.1 The date and hour;

7.1.8.2 The hourly Hg emissions rate (lb/TBtu or lb/GWh, as applicable, calculated according to section 6.2.1 or 6.2.2 of this appendix, rounded to three significant figures), if valid values of Hg concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

7.1.8.3 An identification code for the formula (either the selected equation from Method 19 in section 6.2.1 of this appendix or Equation A-4 in section 6.2.2 of this appendix) used to derive the hourly Hg emission rate from Hg concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

7.1.8.4 A code indicating that the Hg emission rate was not calculated for the hour, if valid data for Hg concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

7.1.9 *Certification and Quality Assurance Test Records.* For any Hg CEMS and sorbent trap monitoring systems used to provide data under this subpart, record the following certification and quality-assurance information:

7.1.9.1 The reference values, monitor responses, and calculated calibration error (CE) values, and a flag to indicate whether the test was done using elemental or oxidized Hg, for all required 7-day calibration error tests and daily calibration error tests of the Hg CEMS;

7.1.9.2 The reference values, monitor responses, and calculated linearity error (LE) or system integrity error (SIE) values for all linearity checks of the Hg CEMS, and for all single-level and 3-level system integrity checks of the Hg CEMS;

7.1.9.3 The CEMS and reference method readings for each test run and the calculated relative accuracy results for all RATAs of the Hg CEMS and/or sorbent trap monitoring systems;

7.1.9.4 The stable stack gas and calibration gas readings and the calculated results for the upscale and downscale stages of all required cycle time tests of the Hg CEMS or, for a batch sampling Hg CEMS, the interval between measured Hg concentration readings;

7.1.9.5 Supporting information for all required RATAs of the Hg monitoring systems, including records of the test dates, the raw reference method and monitoring system data, the results of sample analyses to substantiate the reported test results, and records of sampling equipment calibrations;

7.1.9.6 For sorbent trap monitoring systems, also keep records of the results of all analyses of the

sorbent traps used for routine daily operation of the system, and information documenting the results of all leak checks and the other applicable quality control procedures described in Table 12B-1 of Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

7.1.9.7 For stack gas flow rate, diluent gas, and (if applicable) moisture monitoring systems, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59 of this chapter.

7.2 *Reporting Requirements.*

7.2.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting Hg emissions from each affected unit (or group of units monitored at a common stack) under this subpart:

7.2.1.1 Notifications, in accordance with paragraph 7.2.2 of this section;

7.2.1.2 Monitoring plan reporting, in accordance with paragraph 7.2.3 of this section;

7.2.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 7.2.4 of this section; and

7.2.1.4 Electronic quarterly report submittals, in accordance with paragraph 7.2.5 of this section.

7.2.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) under this subpart in accordance with § 63.10030.

7.2.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack)

under this subpart using Hg CEMS or sorbent trap monitoring system to measure Hg emissions, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

7.2.3.1 Submit the electronic and hard copy information in section 7.1.1.2 of this appendix pertaining to the Hg monitoring systems at least 21 days prior to the applicable date in § 63.9984. Also submit the monitoring plan information in § 75.53.(g) pertaining to the flow rate, diluent gas, and moisture monitoring systems within that same time frame, if the required records are not already in place.

7.2.3.2 Whenever an update of the monitoring plan is required, as provided in paragraph 7.1.1.1 of this section. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

7.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 7.1 of this appendix.

7.2.4 *Certification, Recertification, and Quality-Assurance Test Reporting.* Except for daily QA tests of the required monitoring systems (*i.e.*, calibration error tests and flow monitor interference checks), the results of all required certification, recertification, and quality-assurance tests described in paragraphs 7.1.10.1 through 7.1.10.7 of this section (except for test results previously submitted, *e.g.*, under the ARP) shall be submitted electronically, using the ECMPS Client Tool, either prior to or concurrent with the relevant quarterly electronic emissions report.

7.2.5 *Quarterly Reports.*

7.2.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in § 63.9984, the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack) under this subpart.

7.2.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

7.2.5.3 Each electronic quarterly report shall include the following information:

7.2.5.3.1 The date of report generation;

7.2.5.3.2 Facility identification information;

7.2.5.3.3 The information in paragraphs 7.1.2 through 7.1.8 of this section, as applicable to the Hg emission measurement methodology (or methodologies) used and the units of the Hg emission standard(s); and

7.2.5.3.4 The results of all daily calibration error tests of the Hg CEMS, as described in paragraph 7.1.90.1 of this section and (if applicable) the results of all daily flow monitor interference checks.

7.2.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all Hg emissions from the affected unit(s) under this subpart have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of

each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

Appendix B to Subpart UUUUU---HCl and HF Monitoring Provisions

1. Applicability

These monitoring provisions apply to the measurement of HCl and/or HF emissions from electric utility steam generating units, using CEMS. The CEMS must be capable of measuring HCl and/or HF in the appropriate units of the applicable emissions standard (e.g., lb/MMBtu, lb/MWh, or lb/GWh).

2. Monitoring of HCl and/or HF Emissions

2.1 *Monitoring System Installation Requirements.* Install HCl and/or HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit in accordance with Performance Specification 15 for extractive Fourier Transform Infrared Spectroscopy (FTIR) continuous emissions monitoring systems in appendix B to part 60 of this chapter and § 63.10010(a).

2.2 *Primary and Backup Monitoring Systems.* The provisions pertaining to primary and redundant backup monitoring systems in section 2.2 of appendix A to this subpart apply to HCl and HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit.

2.3 *FTIR Monitoring System Equipment, Supplies, Definitions, and General Operation.* The provisions of

Performance Specification 15 Sections 2.0, 3.0, 4.0, 5.0, 6.0, and 10.0 apply.

3. Initial Certification Procedures

The initial certification procedures for the HCl or HF CEMS used to provide data under this subpart are as follows:

3.1 The HCl and/or HF CEMS must be certified according to Performance Specification 15 using the procedures for gas auditing and comparison to a reference method (RM) as specified in sections 3.1.1 and 3.1.2 below. (**Please Note:** EPA plans to publish a technology neutral performance specification and appropriate on-going quality-assurance requirements for HCl CEMS in the near future along with amendments to this appendix to accommodate their use.)

3.1.1 You must conduct a gas audit of the HCl and/or HF CEMS as described in section 9.1 of Performance Specification 15, with the exceptions listed in sections 3.1.2.1 and 3.1.2.2 below.

3.1.1.1 The audit sample gas does not have to be obtained from the Administrator; however, it must be (1) from a secondary source of certified gases (i.e., independent of any calibration gas used for the daily calibration assessments) and (2) directly traceable to National Institute of Standards and Technology (NIST) or VSL Dutch Metrology Institute (VSL) reference materials through an unbroken chain of comparisons. If audit gas traceable to NIST or VSL reference materials is not available, you may use a gas with a concentration certified to a specified uncertainty by the gas manufacturer.

3.1.1.2 Analyze the results of the gas audit using the calculations in section 12.1 of Performance

Specification 15. The calculated correction factor (CF) from Eq. 6 of Performance Specification 15 must be between 0.85 and 1.15. You do not have to test the bias for statistical significance.

3.1.2 You must perform a relative accuracy test audit or RATA according to section 11.1.1.4 of Performance Specification 15 and the requirements below. Perform the RATA of the HCl or HF CEMS at normal load. Acceptable HCl/HF reference methods (RM) are Methods 26 and 26A in appendix A-8 to part 60 of this chapter, Method 320 in Appendix A to this part, or ASTM D6348-03 (Reapproved 2010) "Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy" (incorporated by reference, see § 63.14), each applied based on the criteria set forth in Table 5 of this subpart.

3.1.2.1 When ASTM D6348-03 is used as the RM, the following conditions must be met:

3.1.2.1.1 The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory;

3.1.2.1.2 In ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);

3.1.2.1.3 For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be 70% >/= R </= 130%; and

3.1.2.1.4 The %R value for each compound must be reported in the test report and all field measurements

corrected with the calculated %R value for that compound using the following equation:

$$\text{Reported Result} = \frac{\text{(Measured Concentration in Stack)}}{\%R} \times 100 \qquad \text{(Eq. 8-1)}$$

3.1.2.2 The relative accuracy (RA) of the HCl or HF CEMS must be no greater than 20 percent of the mean value of the RM test data in units of ppm on the same moisture basis. Alternatively, if the mean RM value is less than 1.0 ppm, the RA results are acceptable if the absolute value of the difference between the mean RM and CEMS values does not exceed 0.20 ppm.

3.2 Any additional stack gas flow rate, diluent gas, and moisture monitoring system(s) needed to express pollutant concentrations in units of the applicable emissions limit must be certified according to part 75 of this chapter.

4. Recertification Procedures

Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: Replacement of a gas analyzer;

complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. On-Going Quality Assurance Requirements

5.1 For on-going QA test requirements for HCl and HF CEMS, implement the quality assurance/quality control procedures of Performance Specification 15 of appendix B to part 60 of this chapter as set forth in sections 5.1.1 through 5.1.3 and 5.3.2 of this appendix.

5.1.1 On a daily basis, you must assess the calibration error of the HCl or HF CEMS using either a calibration transfer standard as specified in Performance Specification 15 Section 10.1 which references Section 4.5 of the FTIR Protocol or a HCl and/or HF calibration gas at a concentration no greater than two times the level corresponding to the applicable emission limit. A calibration transfer standard is a substitute calibration compound chosen to ensure that the FTIR is performing well at the wavelength regions used for analysis of the target analytes. The measured concentration of the calibration transfer standard or HCl and/or HF calibration gas results must agree within +/- 5 percent of the reference gas value after correction for differences in pressure.

5.1.2 On a quarterly basis, you must conduct a gas audit of the HCl and/or HF CEMS as described in section 3.1.1 of this appendix. For the purposes of this appendix, "quarterly" means once every "QA operating quarter" (as defined in section 3.1.20 of appendix A to this subpart). You have the option to use HCl gas in lieu of HF gas for conducting this audit on an HF CEMS. To the extent practicable, perform consecutive quarterly gas audits at least 30 days apart. The initial

quarterly audit is due in the first QA operating quarter following the calendar quarter in which certification testing of the CEMS is successfully completed. Up to three consecutive exemptions from the quarterly audit requirement are allowed for "non-QA operating quarters" (*i.e.*, calendar quarters in which there are less than 168 unit or stack operating hours). However, no more than four consecutive calendar quarters may elapse without performing a gas audit, except as otherwise provided in section 5.3.3.2.1 of this appendix.

5.1.3 You must perform an annual relative accuracy test audit or RATA of the HCl or HF CEMS as described in section 3.1.2 of this appendix. Perform the RATA at normal load. For the purposes of this appendix, "annual" means once every four "QA operating quarters" (as defined in section 3.1.20 of appendix A to this subpart). The first annual RATA is due within four QA operating quarters following the calendar quarter in which the initial certification testing of the HCl or HF CEMS is successfully completed. The provisions in section 5.1.2.4 of appendix A to this subpart pertaining to RATA deadline extensions also apply.

5.2 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable on-going QA test requirements of part 75 of this chapter.

5.3 *Data Validation.*

5.3.1 *Out-of-Control Periods.* A HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-

of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.3.2 *Grace Periods.* For the purposes of this appendix, a "grace period" is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.3.2.1 For the flow rate, diluent gas, and moisture monitoring systems described in section 5.2 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.3.2.2 For the purposes of this appendix, if the deadline for a required gas audit or RATA of a HCl or HF CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.3.2.2.*1 A 168* unit or stack operating hour grace period is available in which to perform the gas audit; or

5.3.2.2.*2 A 720* unit or stack operating hour grace period is available in which to perform the RATA.

5.3.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.3.2.3.1 For a gas audit or RATA of the monitoring systems described in section 5.1 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.3.2.3.2 For the gas audit of a HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit is required for that quarter.

5.3.2.3.3 For the RATA of a HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.3.4 *Conditional Data Validation.* For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, and for the required QA tests when non-redundant backup monitoring systems or temporary like-kind replacement analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a gas audit shall be the same as for a linearity check (*i.e.*, 168 unit or stack operating hours).

6. Missing Data Requirements

For the purposes of this appendix, the owner or operator of an affected unit shall not substitute for

missing data from HCl or HF CEMS. Any process operating hour for which quality-assured HCl or HF concentration data are not obtained is counted as an hour of monitoring system downtime.

7. Bias Adjustment

Bias adjustment of hourly emissions data from a HCl or HF CEMS is not required.

8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the HCl and/or HF CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in section 5.2 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

8.1 *General Requirements for HCl and HF CEMS.*

8.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the HCl and/or HF CEMS in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

8.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to

implement the recordkeeping and reporting requirements of this appendix.

8.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any HCl or HF CEMS in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: Date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded and a written explanation of the procedures used to make the adjustment(s) shall be kept.

8.2 *Specific Requirements for HCl and HF CEMS.* The following requirements are specific to HCl and HF CEMS:

8.2.1 Keep a written record of the procedures used for each type of QA test required for each HCl and HF CEMS. Explain how the results of each type of QA test are calculated and evaluated.

8.2.2 Explain how each component of the HCl and/or HF CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

9. Data Reduction and Calculations

9.1 Design and operate the HCl and/or HF CEMS to complete a minimum of one cycle of operation

(sampling, analyzing, and data recording) for each successive 15-minute period.

9.2 Reduce the HCl and/or HF concentration data to hourly averages in accordance with § 60.13(h)(2) of this chapter.

9.3 Convert each hourly average HCl or HF concentration to an HCl or HF emission rate expressed in units of the applicable emissions limit.

9.3.1 For heat input-based emission rates, select an appropriate emission rate equation from among Equations 19-1 through 19-9 in EPA Method 19 in appendix A-7 to part 60 of this chapter, to calculate the HCl or HF emission rate in lb/MMBtu. Multiply the HCl concentration value (ppm) by 9.43 x 10<-8> to convert it to lb/scf, for use in the applicable Method 19 equation. For HF, the conversion constant from ppm to lb/scf is 5.18 x 10<-8>.

9.3.2 For electrical output-based emission rates, first calculate the HCl or HF mass emission rate (lb/h), using an equation that has the general form of Equation A-2 or A-3 in appendix A to this subpart (as applicable), replacing the value of K with 9.43 x 10<-8> lb/scf-ppm (for HCl) or 5.18 x 10<-8> (for HF) and defining C[h] as the hourly average HCl or HF concentration in ppm. Then, use Equation A-4 in appendix A to this subpart to calculate the HCl or HF emission rate in lb/GWh. If the applicable HCl or HF limit is expressed in lb/MWh, divide the result from Equation A-4 by 10<3>.

9.4 Use Equation A-5 in appendix A of this subpart to calculate the required 30 operating day rolling average HCl or HF emission rates. Round off each 30 operating day average to two significant figures. The

term E[ho] in Equation A-5 must be in the units of the applicable emissions limit.

10. Recordkeeping Requirements

10.1 For each HCl or HF CEMS installed at an affected source, and for any other monitoring system(s) needed to convert pollutant concentrations to units of the applicable emissions limit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 10.1.1 through 10.1.8 of this section.

10.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the HCl and/or HF CEMS and any other monitoring system(s) (*i.e,* flow rate, diluent gas, or moisture systems) needed to convert pollutant concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall explain how the data derived from these systems ensure that all HCl or HF emissions from the unit or stack are monitored and reported.

10.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous HCl or HF monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (*e.g.,* a change to a serial number for a component

of a monitoring system), the owner or operator shall update the monitoring plan.

10.1.1.2 *Contents of the Monitoring Plan.* For HCl and/or HF CEMS, the monitoring plan shall contain the applicable electronic and hard copy information in sections 10.1.1.2.1 and 10.1.1.2.2 of this appendix. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the electronic and hard copy information required for those systems under § 75.53 (g) of this chapter. The electronic monitoring plan shall be evaluated using the ECMPS Client Tool.

10.1.1.2.1 *Electronic.* Record the unit or stack ID number(s); monitoring location(s); the HCl or HF monitoring methodology used (*i.e.*, CEMS); HCl or HF monitoring system information, including, but not limited to: unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; monitor span and range information (if applicable).

10.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations (if applicable); miscellaneous technical justifications.

10.1.2 *Operating Parameter Records.* For the purposes of this appendix, the owner or operator shall record the following information for each operating hour of each affected unit or group of units utilizing a common stack, to the extent that these data are needed to convert pollutant concentration data to the units of the emission standard. For non-operating

hours, record only the items in paragraphs 10.1.2.1 and 10.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 10.1.2.1, 10.1.2.2, and (if applicable) 10.1.2.4 of this section.

10.1.2.1 The date and hour;

10.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

10.1.2.3 The hourly gross unit load (rounded to nearest MWge); and

10.1.2.4 If applicable, the F-factor used to calculate the heat input-based pollutant emission rate.

10.1.3 *HCl and/or HF Emissions Records.* For HCl and/or HF CEMS, the owner or operator must record the following information for each unit or stack operating hour:

10.1.3.1 The date and hour;

10.1.3.2 Monitoring system and component identification codes, as provided in the electronic monitoring plan, for each hour in which the CEMS provides a quality-assured value of HCl or HF concentration (as applicable);

10.1.3.3 The pollutant concentration, for each hour in which a quality-assured value is obtained. For HCl and HF, record the data in parts per million (ppm), rounded to three significant figures.

10.1.3.4 A special code, indicating whether or not a quality-assured HCl or HF concentration value is obtained for the hour. This code may be entered

manually when a temporary like-kind replacement HCl or HF analyzer is used for reporting; and

10.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

10.1.4 *Stack Gas Volumetric Flow Rate Records.*

10.1.4.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required to demonstrate compliance with electrical output-based HCl or HF emissions limits (*i.e.*, lb/MWh or lb/GWh).

10.1.4.2 Use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

10.1.5 *Records of Stack Gas Moisture Content.*

10.1.5.1 Correction of hourly pollutant concentration data for moisture is sometimes required when converting concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

10.1.5.1.1 To calculate electrical output-based pollutant emission rates, when using a CEMS that measures pollutant concentrations on a dry basis; and

10.1.5.1.2 To calculate heat input-based pollutant emission rates, when using certain equations from EPA Method 19 in appendix A-7 to part 60 of this chapter

10.1.5.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage for coal-fired units from § 75.11(b)(1) of this chapter, an Administrator approved default moisture value for

non-coal-fired units (as per paragraph 63.10010(d) of this subpart), or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you elect to use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

10.1.6 *Records of Diluent Gas (CO*[2] *or O* [2] *) Concentration.*

10.1.6.1 To assess compliance with a heat input-based HCl or HF emission rate limit in units of lb/MMBtu, hourly measurements of CO[2] or O[2] concentration are required to convert pollutant concentrations to units of the standard.

10.1.6.2 If hourly measurements of diluent gas concentration are needed, you must use a certified CO[2] or O[2] monitor that meets the requirements of part 75 of this chapter to record the required data. For all diluent gas monitors, you must keep hourly CO[2] or O[2] concentration records, as specified in § 75.57(g) of this chapter.

10.1.7 *HCl and HF Emission Rate Records.* For applicable HCl and HF emission limits in units of lb/MMBtu, lb/MWh, or lb/GWh, record the following information for each affected unit or common stack:

10.1.7.1 The date and hour;

10.1.7.2 The hourly HCl and/or HF emissions rate (lb/MMBtu, lb/MWh, or lb/GWh, as applicable, rounded to three significant figures), for each hour in which valid values of HCl or HF concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and

moisture data, as applicable) are obtained for the hour;

10.1.7.3 An identification code for the formula used to derive the hourly HCl or HF emission rate from HCl or HF concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

10.1.7.4 A code indicating that the HCl or HF emission rate was not calculated for the hour, if valid data for HCl or HF concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

10.1.8 *Certification and Quality Assurance Test Records.* For the HCl and/or HF CEMS used to provide data under this subpart at each affected unit (or group of units monitored at a common stack), record the following information for all required certification, recertification, diagnostic, and quality-assurance tests:

10.1.8.1 *HCl and HF CEMS.*

10.1.8.1.1 For all required daily calibrations (including calibration transfer standard tests) of the HCl or HF CEMS, record the test dates and times, reference values, monitor responses, and calculated calibration error values;

10.1.8.1.2 For gas audits of HCl or HF CEMS, record the date and time of each spiked and unspiked sample, the audit gas reference values and uncertainties. Keep records of all calculations and data analyses required under sections 9.1 and 12.1 of Performance

Specification 15, and the results of those calculations and analyses.

10.1.8.1.3 For each RATA of a HCl or HF CEMS, record the date and time of each test run, the reference method(s) used, and the reference method and HCl or HF CEMS values. Keep records of the data analyses and calculations used to determine the relative accuracy.

10.1.8.2 *Additional Monitoring Systems.* For the stack gas flow rate, diluent gas, and moisture monitoring systems described in section 3.2 of this appendix, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59(a) of this chapter.

11. Reporting Requirements

11.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting HCl and/or HF emissions from each affected unit (or group of units monitored at a common stack):

11.1.1 Notifications, in accordance with paragraph 11.2 of this section;

11.1.2 Monitoring plan reporting, in accordance with paragraph 11.3 of this section;

11.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 11.4 of this section; and

11.1.4 Electronic quarterly report submittals, in accordance with paragraph 11.5 of this section.

11.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of

units monitored at a common stack) in accordance with § 63.10030.

11.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) using HCl and/or HF CEMS, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

11.3.1 Submit the electronic and hard copy information in section 10.1.1.2 of this appendix pertaining to the HCl and/or HF monitoring systems at least 21 days prior to the applicable date in § 63.9984. Also, if applicable, submit monitoring plan information pertaining to any required flow rate, diluent gas, and/or moisture monitoring systems within that same time frame, if the required records are not already in place.

11.3.2 Update the monitoring plan when required, as provided in paragraph 10.1.1.1 of this appendix. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

11.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 10.1 of this appendix.

11.4 *Certification, Recertification, and Quality-Assurance Test Reporting Requirements.* Except for daily QA tests (*i.e.,* calibrations and flow monitor interference checks), which are included in each electronic quarterly emissions report, use the ECMPS Client Tool to submit the results of all required certification, recertification, quality-assurance, and

diagnostic tests of the monitoring systems required under this appendix electronically, either prior to or concurrent with the relevant quarterly electronic emissions report.

11.4.1 For daily calibrations (including calibration transfer standard tests), report the information in § 75.59(a)(1) of this chapter, excluding paragraphs (a)(1)(ix) through (a)(1)(xi).

11.4.2 For each quarterly gas audit of a HCl or HF CEMS, report:

11.4.2.1 Facility ID information;

11.4.2.2 Monitoring system ID number;

11.4.2.3 Type of test (*e.g.*, quarterly gas audit);

11.4.2.4 Reason for test;

11.4.2.5 Certified audit (spike) gas concentration value (ppm);

11.4.2.6 Measured value of audit (spike) gas, including date and time of injection;

11.4.2.7 Calculated dilution ratio for audit (spike) gas;

11.4.2.8 Date and time of each spiked flue gas sample;

11.4.2.9 Date and time of each unspiked flue gas sample;

11.4.2.10 The measured values for each spiked gas and unspiked flue gas sample (ppm);

11.4.2.11 The mean values of the spiked and unspiked sample concentrations and the expected value of the spiked concentration as specified in section 12.1 of Performance Specification 15 (ppm);

11.4.2.12 Bias at the spike level as calculated using equation 3 in section 12.1 of Performance Specification 15; and

11.4.2.13 The correction factor (CF), calculated using equation 6 in section 12.1 of Performance Specification 15.

11.4.3 For each RATA of a HCl or HF CEMS, report:

11.4.3.1 Facility ID information;

11.4.3.2 Monitoring system ID number;

11.4.3.3 Type of test (i.e., initial or annual RATA);

11.4.3.4 Reason for test;

11.4.3.5 The reference method used;

11.4.3.6 Starting and ending date and time for each test run;

11.4.3.7 Units of measure;

11.4.3.8 The measured reference method and CEMS values for each test run, on a consistent moisture basis, in appropriate units of measure;

11.4.3.9 Flags to indicate which test runs were used in the calculations;

11.4.3.10 Arithmetic mean of the CEMS values, of the reference method values, and of their differences;

11.4.3.11 Standard deviation, as specified in Equation 2-4 of Performance Specification 2 in appendix B to part 60 of this chapter;

11.4.3.12 Confidence coefficient, as specified in Equation 2-5 of Performance Specification 2 in appendix B to part 60 of this chapter; and

11.4.3.13 Relative accuracy calculated using Equation 2-6 of Performance Specification 2 in

appendix B to part 60 of this chapter or, if applicable, according to the alternative procedure for low emitters described in section 3.1.2.2 of this appendix. If applicable use a flag to indicate that the alternative RA specification for low emitters has been applied.

11.4.4 *Reporting Requirements for Diluent Gas, Flow Rate, and Moisture Monitoring Systems.* For the certification, recertification, diagnostic, and QA tests of stack gas flow rate, moisture, and diluent gas monitoring systems that are certified and quality-assured according to part 75 of this chapter, report the information in section 10.1.9.3 of this appendix.

11.5 *Quarterly Reports.*

11.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in § 63.10005(g), (h), or (j) (whichever is earlier), the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack).

11.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

11.5.3 Each electronic quarterly report shall include the following information:

11.5.3.1 The date of report generation;

11.5.3.2 Facility identification information;

11.5.3.3 The information in sections 10.1.2 through 10.1.7 of this appendix, as applicable to the type(s) of

monitoring system(s) used to measure the pollutant concentrations and other necessary parameters.

11.5.3.4 The results of all daily calibrations (including calibration transfer standard tests) of the HCl or HF monitor as described in section 10.1.8.1.1 of this appendix; and

11.5.3.5 If applicable, the results of all daily flow monitor interference checks, in accordance with section 10.1.8.2 of this appendix.

11.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all HCl and/or HF emissions from the affected unit(s) have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

[FR Doc. 2012-806 Filed 2-15-12; 8:45 am]

BILLING CODE 6560-50-P

APPENDIX E

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Vol. 76, No. 085

Proposed Rules

ENVIRONMENTAL PROTECTION AGENCY (EPA)

40 CFR Parts 60 and 63

[EPA-HQ-OAR-2009-0234; EPA-HQ-OAR-2011-0044, FRL-9286-1]

RIN 2060-AP52

National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units

Part II

76 FR 24976

DATE: Tuesday, May 3, 2011

ACTION: Proposed rule.

SUMMARY: The United States (U.S.) Environmental Protection Agency (EPA or Agency) is proposing national emission standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generating units (EGUs) under Clean Air Act (CAA or the Act) section 112(d) and proposing revised new source performance standards (NSPS) for fossil fuel-fired EGUs under CAA section

111(b). The proposed NESHAP would protect air quality and promote public health by reducing emissions of the hazardous air pollutants (HAP) listed in CAA section 112(b). In addition, these proposed amendments to the NSPS are in response to a voluntary remand of a final rule. We also are proposing several minor amendments, technical clarifications, and corrections to existing NSPS provisions for fossil fuel-fired EGUs and large and small industrial-commercial-institutional steam generating units.

EFFECTIVE DATE: Comments must be received on or before July 5, 2011. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of having full effect if the Office of Management and Budget (OMB) receives a copy of your comments on or before June 2, 2011.

Public Hearing: EPA will hold three public hearings on this proposal. The dates, times, and locations of the public hearings will be announced separately. Oral testimony will be limited to 5 minutes per commenter. The EPA encourages commenters to provide written versions of their oral testimonies either electronically or in paper copy. Verbatim transcripts and written statements will be included in the rulemaking docket. If you would like to present oral testimony at one of the hearings, please notify Ms. Pamela Garrett, Sectors Policies and Programs Division (C504-03), U.S. EPA, Research Triangle Park, NC 27711, telephone number (919) 541-7966; e-mail: garrett.pamela@epa.gov. Persons wishing to provide testimony should notify Ms. Garrett at least 2 days in advance of each scheduled public hearing. For updates and additional information on the public hearings,

please check EPA's Web site for this rulemaking, http://www.epa.gov/ttn/atw/utility/utilitypg.html. The public hearings will provide interested parties the opportunity to present data, views, or arguments concerning the proposed rule. EPA officials may ask clarifying questions during the oral presentations, but will not respond to the presentations or comments at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at the public hearings.

ADDRESSES: Submit your comments, identified by Docket ID. No. EPA-HQ-OAR-2011-0044 (NSPS action) or Docket ID No. EPA-HQ-OAR-2009-0234 (NESHAP action), by one of the following methods:

- http://www.regulations.gov. Follow the instructions for submitting comments.

- http://www.epa.gov/oar/docket.html. Follow the instructions for submitting comments on the EPA Air and Radiation Docket Web site.

- E-mail: Comments may be sent by electronic mail (e-mail) to a-and-r-docket@epa.gov, Attention EPA-HQ-OAR-2011-0044 (NSPS action) or EPA-HQ-OAR-2009-0234 (NESHAP action).

- Fax: Fax your comments to: (202) 566-9744, Docket ID No. EPA-HQ-OAR-2011-0044 (NSPS action) or Docket ID No. EPA-HQ-OAR-2009-0234 (NESHAP action).

- Mail: Send your comments on the NESHAP action to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460,

Docket ID No. EPA-HQ-OAR-2009-0234. Send your comments on the NSPS action to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460, Docket ID. EPA-HQ-OAR-2011-0044. Please include a total of two copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, OMB, Attn: Desk Officer for EPA, 725 17th St., NW., Washington, DC 20503.

• *Hand Delivery or Courier*: Deliver your comments to: EPA Docket Center, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC 20460. Such deliveries are only accepted during the Docket's normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holiday), and special arrangements should be made for deliveries of boxed information.

Instructions: All submissions must include agency name and respective docket number or Regulatory Information Number (RIN) for this rulemaking. All comments will be posted without change and may be made available online at http://www.regulations.gov, including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through http://www.regulations.gov or e-mail. The http://www.regulations.gov Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment

directly to EPA without going through http://www.regulations.gov, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the http://www.regulations.gov index. Although listed in the index, some information is not publicly available (*e.g.*, CBI or other information whose disclosure is restricted by statute). Certain other material, such as copyrighted material, will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in http://www.regulations.gov or in hard copy at the EPA Docket Center, Room 3334, 1301 Constitution Avenue, NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the Air Docket is (202) 566-1742.

FOR FURTHER INFORMATION CONTACT: For the NESHAP action: Mr. William Maxwell, Energy Strategies Group, Sector Policies and Programs Division, (D243-01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North

Carolina 27711; Telephone number: (919) 541-5430; Fax number (919) 541-5450; E-mail address: maxwell.bill@epa.gov. For the NSPS action: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division, (D243-01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541-4003; Fax number (919) 541-5450; E-mail address: fellner.christian@epa.gov.

SUPPLEMENTARY INFORMATION: The information presented in this preamble is organized as follows:

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C. What should I consider as I prepare my comments to EPA?

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I. General Information

A. Executive Summary

In December 2000, EPA appropriately concluded that it was appropriate and necessary to regulate hazardous air pollutants (HAP) from EGUs. Today, EPA confirms that finding and concludes that it remains appropriate and necessary to regulate these emissions from EGUs. Hazardous air pollutants from EGUs contribute to adverse health and environmental effects. EGUs are by far the largest U.S. anthropogenic sources of mercury (Hg) emissions into the air and emit a number of other HAP. Both the finding in 2000 and our conclusion that it remains appropriate and necessary to regulate HAP from EGUs are supported by the CAA and scientific and technical analyses.

Mercury is a highly toxic pollutant that occurs naturally in the environment and is released into the atmosphere in significant quantities as the result of the burning of fossil fuels. Mercury in the environment is transformed into a more toxic form, methylmercury (MeHg), and because it is also a persistent pollutant, it accumulates in the food chain, especially the tissue of fish. When people consume these fish they consume MeHg, the consumption of which may cause neurotoxic effects. Children, and, in particular, developing fetuses, are especially susceptible to MeHg effects because their developing bodies are more highly sensitive to its effects. In the December 2000 Finding, we estimated that about 7 percent of women of child-bearing age are exposed to MeHg at a level capable of causing adverse effects in the developing fetus, and that about 1 percent were exposed to 3 to 4 times that level. 65 FR 79827. Moreover, in the 1997 Mercury Study Report to Congress (the "Mercury

Study"),[1] we concluded that exposures among specific subpopulations including anglers, Asian-Americans, and members of some Native American Tribes may be more than two-times greater than those experienced by the average U.S. population (U.S. EPA 1997 Mercury Study Report to Congress, Volume IV, page 7-2).

In addition to Hg, EGUs are significant emitters of HAP metals such as arsenic (As), nickel (Ni), cadmium (Cd), and chromium (Cr), which can cause cancer; HAP metals with potentially serious noncancer health effect such as lead (Pb) and selenium (Se); and other toxic air pollutants such as the acid gases hydrogen chloride (HCl) and hydrogen fluoride (HF). Adverse noncancer health effects associated with non-Hg EGU HAP include chronic health disorders (*e.g.*, irritation of the lung, skin, and mucus membranes, effects on the central nervous system, and damage to the kidneys), and acute health disorders (*e.g.*, lung irritation and congestion, alimentary effects such as nausea and vomiting, and effects on the kidney and central nervous system). Three of the key metal HAP emitted by EGUs (As, Cr, and Ni) have been classified as human carcinogens, while another (Cd) is classified as a probable human carcinogen. Current national emissions inventories indicate that EGUs are responsible for 62 percent of the national total emissions of As, 22 percent of the national total emissions of Cr, and 28 percent of the national total emissions of Ni to the atmosphere. Notably, EGUs are also responsible for 83 percent of the national total emissions of Se to the atmosphere.

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[1] U.S. EPA. 1997. Mercury Study Report to Congress. EPA-452/R-97-003 December 1997.

Congress recognized the threats posed by emissions of HAP and was dissatisfied with the pace of EPA's progress in reducing them prior to 1990. As a result, it enacted significant changes to the CAA that required EPA to develop stringent standards for the control of these pollutants from both stationary and mobile sources. Congress included the requirements in the 1990 CAA amendments regarding acid rain that would reduce emissions of certain criteria pollutants from EGUs and result in the installation of controls that might achieve HAP emission reduction co-benefits. For that reason, it added the requirement for EPA to make a finding before it could regulate EGUs under section 112. Specifically, Congress required in the air toxics provisions that EPA conduct a study of the public health hazards anticipated to remain from EGU HAP emissions after imposition of these other provisions and regulate EGUs under section 112 if the Agency found, after considering the results of the study, that such regulation was appropriate and necessary. Congress also required EPA to conduct a study of Hg emissions from EGUs and other sources and consider the health and environmental effects of the emissions and the availability and cost of control technologies.

Responding to Congress, EPA published the required studies detailing the hazards posed by emissions of Hg and the risks posed by emissions of Hg and other HAP from fossil fuel-fired EGUs. Following the publication of the studies and after collecting additional relevant data, EPA concluded in December 2000 that the threats to public health and the environment from emissions of Hg and other HAP from EGUs made it both appropriate and necessary to adopt regulations under section 112 to reduce the emissions of Hg and other HAP from coal- and oil-fired

EGUs. As a result of its findings, EPA added these sources to the list of stationary sources subject to regulations governing the emissions of HAP. However, in a rulemaking effort completed in 2005, EPA reversed its findings and instead adopted regulations under other provisions of the CAA. The DC Circuit Court vacated the resulting regulations, noting that EPA had sidestepped important legal requirements in the CAA that govern the delisting of source categories. Those requirements provide that EPA can delist a source category only if it can demonstrate that no source within the listed category poses a lifetime cancer risk above one in one million to the individual most exposed and that emissions from no source in the category exceed the level that is adequate to protect public health with an ample margin of safety and that no adverse environmental effects will result from the emissions of any source. CAA 112(c)(9)(B). The DC Circuit Court's action restored EPA's December 2000 determination that it was appropriate and necessary to regulate coal- and oil-fired EGUs under section 112, and EGUs remain a listed source category.

EPA reasonably concluded in December 2000, based on the information available to the Agency at that time, that it was appropriate and necessary to regulate EGUs under section 112. Now, more than 10 years have passed since EPA's determination that toxic emissions from coal- and oil-fired EGUs pose a threat to public health and the environment. Although not required, EPA conducted additional, extensive technical analyses based on more recent data, and those analyses confirm that it remains appropriate and necessary to regulate HAPs from coal- and oil-fired EGUs. Accordingly and without further delay, we are proposing a set of HAP emission standards for coal- and oil-fired EGUs that can be met with existing

technology that has been available for a significant time.

EPA acknowledges that although EGUs contribute significantly to the total amount of U.S. anthropogenic Hg emissions, other sources both here and abroad also contribute significantly to the global atmospheric burden and U.S. deposition of Hg. It is estimated that the U.S. contributes 5 percent to global anthropogenic Hg and 2 percent the total global Hg pool.[2] However, as the U.S. Supreme Court has noted in decisions as recently as Massachusetts v. EPA, regarding the problem of climate change, it is not necessary to show that a problem will be entirely solved by the action being taken, nor that it is necessary to cure all ills before addressing those judged to be significant. 549 U.S. 497, 525 (2007).

At the time it published the December 2000 Finding, EPA identified certain technologies capable of significantly reducing Hg and other HAP emissions. Since then, additional technologies and improvements to those previously identified have become available. These technologies are also often effective at reducing significantly the emissions of other conventional pollutants such as SO[2] and PM, thereby conferring even greater health co-benefits. As today's notice discusses further, the reductions expected from the adopted final rule will produce substantially greater co-benefits to health and the environment than they will cost to affected companies. We further believe that these reductions can be achieved without significantly

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[2] Based on 2005 U.S. emissions of 105 tons, and global emissions of 2,100 tons from UNEP. Mercury emissions are discussed more fully in Section III.D.1 of this preamble.

affecting the availability and cost of electricity to consumers. In those instances in which such concerns do arise, the Federal government will work with companies to ensure a reliable and reasonably-priced supply of electricity. Moreover, in its assessment of the impacts of today's proposed rule on jobs and the economy, EPA finds that more jobs will be created in the air pollution control technology production field than may be lost as the result of compliance with these proposed rules.

A number of EGUs operating today were built in the 1950s and 1960s, using now-obsolete and inefficient technologies. Today, new units are far more efficient in their production of electricity, their use of fuel, and the relative quantities of pollution emitted. To the extent that some of the oldest, least efficient, least controlled units are retired by companies who elect not to invest in controlling them, assessments included in the docket to today's notice of proposed rulemaking indicate that there will be a sufficient supply of electricity from newer units. In fact, one consequence of today's proposed rule, if adopted as a final rule, will be that the market for electricity in the U.S. will be more level and no longer skewed in favor of the higher polluting units that were exempted from the CAA at its inception on Congress' assumption that their useful life was near an end. Thus, this proposed rule will require companies to make a decision—control HAP emissions from virtually uncontrolled sources or retire these sometimes 60 year old units and shift their emphasis to more efficient, cleaner modern methods of generation, including modern coal-fired generation.

For the reasons summarized above and discussed in detail in this document, the standards being proposed today will be effective at significantly reducing

emissions of Hg and an array of other toxic pollutants from coal- and oil-fired EGUs. In addition, as a result of the HAP reductions and co-benefits of these rules, many premature deaths from exposure to air pollution will be avoided by the application of controls that are well-known, broadly applied, and available. To the extent that isolated issues remain concerning the availability of electricity in some more remote parts of the country, we believe that EPA has the ability to work with companies making good faith efforts to comply with the standards so that consumers in those areas are not adversely affected.

Consistent with the recently issued Executive Order (EO) 13563, "Improving Regulation and Regulatory Review," we have estimated the cost and benefits of the proposed rule. The estimated net benefits of our proposed rule at a 3 percent discount rate are $ 48 to 130 billion or $ 42 to $ 120 billion at a 7 percent discount rate.

1178a

Summary of the Monetized Benefits, Social Costs, and Net Benefits for the Proposed Rule in 2016

[Millions of 2007$] fna

	3% Discount rate	7% Discount rate
Total Monetized Benefits fnb	$ 59,000 to $ 140,000	$ 53,000 to $ 130,000.
Hg-related Benefits fnc	$ 4.1 to $ 5.9	$ 0.45 to $ 0.89.
CO[2]-related Benefits	$ 570	$ 570.
PM[2.5]-related	$ 58,000 to $ 140,000	$ 53,000 to $ 120,000.
Co-benefits fnd		
Total Social Costs fne	$ 10,900	$ 10,900.
Net Benefits	$ 48,000 to $ 130,000	$ 42,000 to $ 130,000.
Non-monetized Benefits	Visibility in Class I areas.	
	Cardiovascular effects of Hg exposure.	
	Other health effects of Hg exposure.	
	Ecosystem effects.	
	Commercial and non-freshwater fish consumption.	

fna All estimates are for 2016, and are rounded to two significant figures. The net present value of reduced CO[2] emissions are calculated differently than other benefits. The same discount rate used to discount the value of damages from future emissions (SCC at 5, 3, 2.5 percent) is used to calculate net present value of SCC for internal consistency. This table shows monetized CO[2] co-benefits at discount rates at 3 and 7 percent that were calculated using the global average SCC estimate at a 3 percent discount rate because the interagency workgroup on this topic deemed this marginal value to be the central value. In section 6.6

of the RIA we also report the monetized CO[2] co-benefits using discount rates of 5 percent (average), 2.5 percent (average), and 3 percent (95th percentile).

fnb The total monetized benefits reflect the human health benefits associated with reducing exposure to MeHg, PM[2.5], and ozone.

fnc Based on an analysis of health effects due to recreational freshwater fish consumption.

fnd The reduction in premature mortalities from account for over 90 percent of total monetized PM[2.5] benefits.

fne Social costs are estimated using the MultiMarket model, in order to estimate economic impacts of the proposal to industries outside the electric power sector. Details on the social cost estimates can be found in Chapter 9 and Appendix E of the RIA.

For more information on how EPA is addressing EO 13563, see the executive order discussion, later in the preamble.

B. Does this action apply to me?

The regulated categories and entities potentially affected by the proposed standards are shown in Table 1 of this preamble.

Table 1—Potentially Affected Regulated Categories and Entities

Category	NAICS code fn1	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal government	fn2 221122	Fossil fuel-fired electric utility steam generating units owned by the Federal government.
State/local/tribal government	fn2 221122	Fossil fuel-fired electric utility steam generating units owned by municipalities.
	921150	Fossil fuel-fired electric utility steam generating units in Indian country.

fn1 North American Industry Classification System.

fn2 Federal, State, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. To determine whether your facility, company, business, organization, etc., would be regulated by this action, you should examine the applicability criteria in 40 CFR 60.40, 60.40Da, or 60.40c or in 40 CFR 63.9982. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

C. What should I consider as I prepare my comments to EPA?

Do not submit information containing CBI to EPA through http://www.regulations.gov or e-mail. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404-02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Docket ID EPA-HQ-OAR-2011-0044 (NSPS action) or Docket ID EPA-HQ-OAR-2009-0234 (NESHAP action). Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD-ROM that you mail to EPA, mark the outside of the disk or CD-ROM as CBI and then identify electronically within the disk or CD-ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

D. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of this proposed rule will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of the proposed rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: http://www.epa.gov/ttn/oarpg/. The TTN provides information and technology exchange in various areas of air pollution control.

E. When would a public hearing occur?

EPA will hold three public hearings on this proposal. The dates, times, and locations of the public hearings will be announced separately. If you would like to present oral testimony at one of the hearings, please notify Ms. Pamela Garrett, Sectors Policies and Programs Division (C504-03), U.S. EPA, Research Triangle Park, NC 27711, telephone number (919) 541-7966; e-mail: garrett.pamela@epa.gov. Persons wishing to provide testimony should notify Ms. Garrett at least 2 days in advance of the public hearings. For updates and additional information on the public hearings, please check EPA's Web site for this rulemaking, http://www.epa.gov/ttn/atw/utility/utilitypg.html.

II. Background Information on the NESHAP

In 1990, Congress substantially rewrote provisions of the CAA addressing emissions of HAP from large and small stationary sources in the U.S. Collectively, these sources emit into the air millions of pounds of HAP each year, chemicals that are known to cause or are suspected of causing cancer, birth defects, reproduction problems, and other serious health effects. Many of the sources that emit air toxics are located in urban areas, which generally include predominantly low income, minority or otherwise vulnerable communities, where dense populations mean that large numbers of people may be exposed.

Since 1990, EPA has promulgated regulations covering over 50 industrial sectors, requiring the use of available control technology and other practices to reduce emissions. These standards have reduced emissions of HAP from American industry by more than 60 percent. HAP emissions from smaller sources

such as dry cleaners and auto body shops have declined by 30 percent, also due to CAA standards. Greater reductions are expected as greater numbers of smaller sources adopt pollution prevention, efficiency, or install control technologies to comply with EPA emission standards. Emissions from the mobile source sector have also been addressed. Controls for fuels and vehicles are expected to reduce selected HAP from vehicles by more than 75 percent by 2020.

EGUs are the most significant source of HAP in the country that remains unaddressed by Congress's air toxics program. EGUs emit multiple HAP of concern and are by far the largest remaining source of Hg, which is one of the more highly toxic chemicals on Congress's list of HAP and which, once released, stays in the environment permanently. Coal- and oil-fired EGUs also emit HAP such as As, other metals and acid gases in amounts significantly higher than almost any other industrial sector. They are located in nearly every state, and emissions from their stacks affect people nearby as well as hundreds of miles away.

Congress provided a specific path for EPA to regulate HAP emissions from EGUs. It gave explicit instructions about scientific studies EPA needed to develop and then consider in determining whether it was "appropriate and necessary" to regulate HAP emissions from EGUs. Congress anticipated that EPA would complete the studies by 1994. In 2000, EPA found that it was indeed "appropriate and necessary" to regulate HAP emissions from EGUs under section 112. In the decade that has passed since EPA made that finding, EGUs have continued to emit Hg and other HAP, and there are still no national limits on the amount of Hg and other HAP that EGUs can release into the air. And, although some plants have installed

available and effective control technologies that reduce these emissions, there is no requirement for EGUs to control for Hg and other HAP.

As our new analyses demonstrate, it remains both appropriate and necessary to set standards for coal- and oil-fired EGUs to protect public health and the environment from the adverse effects of HAP emissions from EGUs. The Agency's appropriate and necessary finding was correct in 2000, and it remains correct today. EPA proposes to set standards for coal- and oil-fired EGUs that will reduce emissions of Hg, Ni and other metal HAP, acid gas HAP, and other harmful HAP. These standards are based on available control technologies and other practices already used by the better-controlled and lower-emitting EGUs. They are achievable, we believe they can be implemented without disruption to the reliable provision of electricity, and will deliver health protection across the U.S.

In this section, we provide an overview of the relevant statutory, regulatory, and litigation background.

A. Statutory Background

Congress enacted section 112 to address HAP emissions from stationary sources. Section 112 contains provisions specific to EGUs, which we will address in this preamble, but we begin with a summary of the overall structure and purpose of the section 112 program.

Prior to the 1990 Amendments, the CAA required EPA to regulate HAP solely on the basis of risk to human health. Legislative History of the CAA Amendments of 1990 ("Legislative History"), at 3174-75, 3346 (Comm. Print 1993). Congress was

dissatisfied with the slow pace of exclusively risk-based regulation of HAP prior to 1990, however, and, as a result, substantially amended the CAA in 1990, setting forth a two-stage approach for regulating HAP emissions. Under the first stage, Congress directed EPA to issue technology-based emission standards for listed source categories. CAA sections 112 (c)-(d). In the second stage, which occurs "within eight years" of the imposition of the technology-based standards, EPA must consider whether residual risks remain after imposition of the MACT standards that warrant more stringent standards to protect human health or to prevent an adverse environmental effect. CAA section 112(f)(2)(A).

In addition to adopting this two-phased approach to standard-setting, Congress included a series of rigorous deadlines for EPA, including deadlines for listing categories and issuing emission standards for such categories. See, *e.g.*, CAA section 112(e)(1). Thus, in substantially amending CAA section 112 in 1990, Congress sought prompt and permanent reductions of HAP emissions from stationary sources—first through technology-based standards, and then further, as necessary, through risk-based standards designed to protect human health and the environment.

The criteria for regulation differ in section 112 depending on whether the source is a major source or an area source. A "major source" is any stationary source[3] or group of stationary sources at a single location and under common control that emits or has the potential to emit 10 tons or more per year of any

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[3] A "stationary source" of HAP is any building, structure, facility or installation that emits or may emit any air pollutant. See CAA Section 112(a)(3).

HAP or 25 tons or more per year of any combination of HAP. See CAA 112(a)(1). An "area source" is any stationary source of HAP that is not a "major source." See CAA 112(a)(2). For major sources, EPA must list a category under section 112(c)(1) if at least one stationary source in the category meets the definition of a major source.[4] For area sources, EPA must list if: (1) EPA determines that the category of area sources presents a threat of adverse effects to human health or the environment that warrants regulation under CAA section 112; or (2) the category of area sources falls within the purview of CAA section 112(k)(3)(B) (the Urban Area Source Strategy). See CAA section 112(c)(3).

Congress established a specific structure for determining whether to regulate EGUs under section 112.[5] Specifically, Congress enacted CAA section 112(n)(1).

In section 112(n)(1)(A), EPA is directed to conduct a study to evaluate the hazards to public health reasonably anticipated to occur as the result of HAP emissions from EGUs after imposition of the

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[4] Congress required EPA to publish a list of categories and subcategories of major sources and area sources by November 15, 1991. See CAA 112(c)(1) & (c)(3). EPA published the initial list on July 16, 1992. See 57 FR 31576, July 16, 1992. EPA did not include EGUs on the initial section 112(c) list because Congress required EPA to conduct and consider the results of the study required by section 112(n)(1)(A) before regulating these units. At the time of the initial listing, EPA had not completed the study required by section 112(n)(1)(A).

[5] "Electric utility steam generating unit" is defined as any "fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale." See CAA 112(a)(8).

requirements of the CAA, and to report the results of such study to Congress by November 15, 1993 (Utility Study Report to Congress;[6] the "Utility Study"). We discuss this study further below in conjunction with the other studies Congress required be conducted with respect to EGUs under section 112(n)(1). The last sentence of section 112(n)(1)(A) provides that EPA shall regulate EGUs under CAA section 112 "if the Administrator finds such regulation is appropriate and necessary, after considering the results of the [Utility Study] * * *" Thus, section 112(n)(1)(A) governs how the Administrator decides whether to list EGUs for regulation under section 112. *See New Jersey*, 517 F.3d at 582 ("Section 112(n)(1) governs how the Administrator decides whether to list EGUs; it says nothing about delisting EGUs.").

Once a source category is listed pursuant to section 112(c), the next step is for EPA to establish technology-based emission standards under section 112(d). Under section 112(d), EPA must establish emission standards for major sources that "require the maximum degree of reduction in emissions of the HAP subject to this section" that EPA determines is achievable taking into account certain statutory factors. These are referred to as "maximum achievable control technology" or "MACT" standards. The MACT standards for existing sources must be at least as stringent as the average emissions limitation achieved by the best performing 12 percent of existing sources in the category (for which the Administrator has emissions information) or the best performing 5 sources for source categories with less than 30 sources.

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[6] US EPA. Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units –Final Report to Congress. EPA-453/R-98-004a. February 1998.

See CAA section 112(d)(3)(A) and (B). This level of minimum stringency is referred to as the MACT floor, and EPA cannot consider cost in setting the floor. For new sources, MACT standards must be at least as stringent as the control level achieved in practice by the best controlled similar source. See CAA section 112(d)(3). EPA also must consider more stringent "beyond-the-floor" control options. When considering beyond-the-floor options, EPA must consider not only the maximum degree of reduction in emissions of HAP, but must take into account costs, energy, and nonair quality health and environmental impacts when doing so. *See Cement Kiln Recycling Coal. v. EPA*, 255 F.3d 855, 857-58 (D.C. Cir. 2001).

CAA section 112(d)(4) authorizes EPA to set a health-based standard for a limited set of HAP for which a health threshold has been established, and that standard must provide for "an ample margin for safety." 42 U.S.C. 7412(d)(4). As these standards are potentially less stringent than MACT standards, the Agency must have detailed information on HAP emissions from the subject sources and sources located near the subject sources before exercising its discretion to set such standards.

For area sources, section 112(d)(5) authorizes EPA to issues standards or requirements that provide for the use of generally available control technologies (GACT) or management practices in lieu of promulgating standards pursuant to sections 112(d)(2) and (3).

As noted above, Congress required that various reports concerning EGUs be completed. The first report, the Utility Study, required EPA to evaluate the hazards to public health reasonably anticipated to occur as the result of HAP emissions from EGUs after

imposition of the requirements of the CAA. This report was required by November 15, 1993. The second report, due on November 15, 1994, directed EPA to "conduct a study of mercury emissions from [EGUs], municipal waste combustion units, and other sources, including area sources." *See* CAA section 112(n)(1)(B). In conducting the Mercury study Congress directed EPA to "consider the rate and mass of emissions, the health and environmental effects of such emissions, technologies which are available to control such emissions, and the costs of such technologies." Id. EPA completed both of these reports by 1998.

The last required report was to be completed by the National Institute of Environmental Health Sciences (NIEHS) and submitted to Congress by November 15, 1993. CAA section 112(n)(1)(C) directed NIEHS to conduct "a study to determine the threshold level of Hg exposure below which adverse human health effects are not expected to occur." In conducting this study, NIEHS was to determine "a threshold for mercury concentrations in the tissue of fish which may be consumed (including consumption by sensitive populations) without adverse effects to public health." *Id.* NIEHS submitted this Report to Congress in August, 1995.

In addition, Congress, in conference report language associated with EPA's fiscal year 1999 appropriations, directed EPA to fund the National Academy of Sciences (NAS) to perform an independent evaluation of the available data related to the health impacts of MeHg ("Toxicological Effects of Methylmercury," hereinafter, NAS Study or MeHg Study).[7] H.R. Conf.

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[7] National Research Council (NAS). 2000. Toxicological Effects of Methylmercury. Committee on the Toxicological Effects of Methylmercury, Board on Environmental Studies and

Rep. No. 105-769, at 281-282 (1998). Specifically, NAS was tasked with advising EPA as to the appropriate reference dose (RfD) for MeHg, which is the amount of a chemical which, when ingested daily over a lifetime, is anticipated to be without adverse health effects to humans, including sensitive subpopulations. 65 FR 79826. In that same conference report, Congress indicated that EPA should not make the appropriate and necessary regulatory determination for Hg emissions until EPA had reviewed the results of the NAS Study. *See* H.R. Conf. Rep. No. 105-769, at 281-282 (1998).

The NAS Study evaluated the same issues as those required to be considered under section 112(n)(1)(C). The NAS Study was completed 5 years after the NIEHS Study, and, thus, considered additional information not available to NIEHS. Because Congress required that the same issues be addressed in both the NAS and NIEHS Studies and the NAS Study was issued after the NIEHS study, we discuss, for purposes of this document, the content of the NAS Study, as opposed to the NIEHS Study.

B Regulatory and Litigation Background

EPA conducted the studies required by section 112(n)(1) concerning utility HAP emissions. Prior to issuance of the Mercury Study, EPA engaged in two extensive external peer reviews of the document. Although EPA missed the statutory deadline for completing the studies, the Mercury Study and the Utility Study were complete by 1998. The NIEHS

Toxicology, National Research Council. Many of the peer-reviewed articles cited in this section are publications originally cited in the NAS report.

study was completed in 1995, and the NAS Study was completed in 2000.

In December 2000, after considering public input, the studies required by section 112(n)(1) and other relevant information, including Hg emissions data from EGUs, EPA determined that it was appropriate and necessary to regulate EGUs under CAA section 112. Based on that determination, the Agency listed such units for regulation under section 112(c).

Pursuant to a settlement agreement, the deadline for issuing emission standards was March 15, 2005. However, instead of issuing emission standards pursuant to section 112(d), on March 15, 2005, EPA delisted EGUs, finding that it was neither appropriate nor necessary to regulate such units under section 112. That attempt to delist was subsequently invalidated by the DC Circuit Court.

1. Studies Related to HAP Emissions From EGUs

a. The Utility Study

EPA issued the Utility Study in February 1998, over 4 years after the statutory deadline. The Utility Study included numerous analyses. EPA first collected HAP emissions test data from 52 EGUs, including a range of coal-, oil-, and natural gas-fired units, and the test data along with facility specific information were used to estimate HAP emissions from all 684 utility facilities. EPA determined that 67 HAP were emitted from EGUs. In addition, the study evaluated HAP emissions based on two scenarios: (1) 1990 base year; and (2) 2010 projected emissions. The 2010 scenario was selected to meet the section 112(n)(1)(A) mandate to evaluate hazards "after imposition of the requirements of the Act." EPA also considered

potential control strategies for the identified HAP consistent with section 112(n)(1)(A).

EPA evaluated exposures, hazards, and risks due to HAP emissions from coal-, oil-, and natural gas-fired EGUs. EPA conducted a screening level assessment of all 67 HAP to prioritize the HAP for further analysis. A total of 14 HAP were identified as priority HAP that would be further assessed. Twelve HAP (As, beryllium (Be), Cd, Cr, manganese (Mn), Ni, HCl, HF, acrolein, dioxins, formaldehyde, and radionuclides) were identified as a priority for further assessment based on inhalation exposure and risk. Six HAP (Hg, radionuclides, As, Cd, Pb, and dioxins) were considered a priority for multipathway assessment of exposure and risk.

Based on the inhalation estimates for the priority HAP, EPA determined that As and Cr emissions from coal-fired EGUs and Ni emissions from oil-fired EGUs contributed most to the potential cancer related inhalation risks, but those risks were not high. The non-cancer risk assessment due to inhalation exposure indicated exposures were well below the reference levels.

The Agency also conducted multipathway assessments for the six HAP identified above. Based on these analyses, EPA determined that Hg from coal-fired EGUs was the HAP of greatest potential concern. In addition, the screening multipathway assessments for dioxins and As suggested that these two HAP were of potential for multipathway risk.

In addition to the 1990 analysis, EPA also estimated emissions and inhalation risks for the year 2010. HAP emissions from coal-fired utilities were predicted to increase by 10 to 30 percent by the year 2010.

Predicted changes included the installation of scrubbers for a small number of facilities, the closing of a few facilities, and an increase in fuel consumption of other facilities. For oil-fired plants, emissions and inhalation risks were estimated to decrease by 30 to 50 percent by the year 2010, primarily due to projected reductions in use of oil for electricity generation. Multipathway risks for 2010 were not assessed.

In estimating future emissions from EGUs, EPA primarily evaluated the effect of implementation of the Acid Rain Program (ARP) on HAP emissions from EGUs. The 2010 scenario also included estimated changes in emissions resulting from projected trends in fuel choices and power demands.

Table 2 of this preamble presents estimated emissions for a subset of priority HAP for 1990 and 2010.

Table 2—Nationwide Emissions for Six Priority HAP, tpy

HAP	Coal		Oil		Natural gas	
	1990	2010	1990	2010	1990	2010
Arsenic	61	71	5	3	0.15	0.25
Chromium	73	87	4.7	2.4		
Mercury	46	60	0.25	0.13	0.0015	0.024
Nickel	58	69	390	200	2.2	3.5
Hydrogen chloride	143,000	155,000	2,900	1,500	NM	NM
Hydrogen fluoride	20,000	26,000	140	73	NM	NM

Numerous potential alternative control strategies for reducing HAP emissions from EGUs were identified. These included pre-combustion controls

(*e.g.*, fuel switching, coal cleaning), post combustion controls (*e.g.*, PM controls, SO[2] controls), and improving efficiency in supply or demand. For example, coal cleaning tends to remove at least some of all the trace metals. EPA also concluded that PM controls tend to effectively remove the trace metals (excluding Hg). The Utility Study also found that flue gas desulfurization (FGD) units were less effective at removing trace metals and exhibited more variability in removal of those metals than PM control, but FGD were more effective at reducing acid gas HAP.

b. The Mercury Study

EPA issued the Mercury Study in December 1997, 3 years after the statutory deadline. The Mercury Study assessed the magnitude of U.S. Hg emissions by source, the health and environmental implications of those emissions, and the availability and cost of control technologies.

According to the Mercury Study, Hg cycles in the environment as a result of natural and human (anthropogenic) activities. Most of the Hg in the atmosphere is elemental Hg vapor, which circulates in the atmosphere for up to a year, and, hence, can be widely dispersed and transported thousands of miles from likely sources of emission. The Mercury Study also found that most of the Hg in water, soil, sediments, or plants and animals is in the form of inorganic Hg salts and organic forms of Hg (*e.g.*, MeHg). The inorganic form of Hg, when either bound to airborne particles or in a gaseous form, is readily removed from the atmosphere by precipitation and is also dry deposited. Wet deposition is the primary mechanism for transporting Hg from the atmosphere to surface waters and land. Even after it deposits, Hg commonly is emitted back to the atmosphere either as

a gas or associated with particles, to be re-deposited elsewhere.

The Mercury Study estimated that in 1994-1995, anthropogenic U.S. Hg emissions were about 158 tons annually. Roughly 87 percent of those emissions were from combustion sources, including waste and fossil fuel combustion. According to the Mercury Study, current anthropogenic emissions were only one part of the Hg cycle. The Mercury Study noted that current releases from human activities were adding to the Hg reservoirs that already exist in land, water, and air, both naturally and as a result of prior human activities. The Mercury Study concluded that the flux of Hg from the atmosphere to land or water at any one location is comprised of contributions from the natural global cycle, including re-emissions from the oceans, international sources, regional sources, and local sources.

The Mercury Study further described a computer simulation of long-range transport of Hg, which suggested that about one-third (approximately 52 tons) of U.S. anthropogenic emissions are deposited, through wet and dry deposition, within the lower 48 states. The remaining two-thirds (approximately 107 tons) was estimated to be transported outside of U.S. borders where it would diffuse into the global reservoir. The computer simulation further suggested that another 35 tons of Hg from the global reservoir outside the U.S. was deposited annually in the U.S. for a total deposition in the U.S. of roughly 87 tons per year (tpy).

The Mercury Study also found that fish consumption dominates the pathway for human and wildlife exposure to MeHg and that there was a plausible link between anthropogenic releases of Hg

from industrial and combustion sources in the U.S. and MeHg in fish. In the Mercury Study, EPA explained that, given the current scientific understanding of the environmental fate and transport of this element, it was not possible to quantify how much of the MeHg in fish consumed by the U.S. population results from U.S. anthropogenic emissions, as compared to other sources of Hg (such as natural sources and re-emissions from the global pool).

The Mercury Study noted that those who regularly and frequently consume large amounts of fish—either marine species that typically have much higher levels of MeHg than other species, or freshwater fish that have been affected by Hg pollution—are more highly exposed. Because the developing fetus may be the most sensitive to the effects from MeHg, women of child-bearing age were the population of greatest interest. EPA concluded in the Mercury Study that approximately 7 percent of women of child-bearing age (*i.e.*, between the ages of 15 and 44) were exposed to MeHg at levels exceeding the RfD.

Finally, the Mercury Study concluded that piscivorous (fish-eating) birds and mammals were more highly exposed to Hg than any other known component of aquatic ecosystems, and that adverse effects of Hg on fish, birds and mammals include death, reduced reproductive success, impaired growth and development, and behavioral abnormalities. The Mercury Study also evaluated Hg emissions control technologies and the costs of such technologies.

c. The NAS Methylmercury Study

In the appropriations report for EPA's fiscal 1999 funding, Congress directed EPA to fund the NAS to perform an independent study on the toxicological

effects of MeHg and to prepare recommendations on the establishment of a scientifically appropriate MeHg exposure RfD. In response, EPA contracted with NAS, which conducted an 18-month study of the available data on the health effects of MeHg and reported its findings to EPA in July 2000.

The EPA included four charges to NAS: (1) Evaluate the body of evidence that led to EPA's current RfD for MeHg, and on the basis of available human epidemiological and animal toxicity data, determine whether the critical study, end point of toxicity, and uncertainty factors used by EPA in the derivation of the RfD for MeHg are scientifically appropriate, including consideration of sensitive populations; (2) evaluate any new data not considered in the Mercury Study that could affect the adequacy of EPA's MeHg RfD for protecting human health; (3) consider exposures in the environment relevant to evaluation of likely human exposures (especially to sensitive subpopulations and especially from consumption of fish that contain MeHg), and include in the evaluation a focus on those elements of exposure relevant to the establishment of an appropriate RfD; and (4) identify data gaps and make recommendations for future research.

The NAS held both public and closed sessions wherein they evaluated data and presentations from government agencies, trade organizations, public interest groups, and concerned citizens. The NAS also evaluated new findings that had emerged since the development of EPA's 1995 RfD and met with the investigators of major ongoing epidemiological studies.

The NAS Study concluded that the value of EPA's 1995 RfD for MeHg, 0.1 micrograms per kilogram

([mu]g/kg) per day, was a scientifically appropriate level for the protection of public health. The NAS Study further concluded that data from both human and animal studies indicated that the developing nervous system was a sensitive target organ for low-dose MeHg exposure. The NAS Study indicated that there was evidence that exposure to MeHg in humans and animals can have adverse effects on both the developing and adult cardiovascular system. Some of the studies observed adverse cardiovascular effects at or below MeHg exposure levels associated with neurodevelopmental effects. The weight of evidence for carcinogenicity of MeHg was inconclusive. There was also evidence from animal studies that the immune and reproductive systems are sensitive targets for MeHg toxicity.

According to the NAS Study, the estimates of MeHg exposures in the U.S. population indicated that the risk of adverse effects from then-current MeHg exposures in the majority of the population was low. However, the NAS Study concluded that individuals with high MeHg exposures from frequent fish consumption might have little or no margin of safety (*i.e.*, exposures of high-end consumers are close to those with observable adverse effects). The NAS Study also noted that the population at highest risk was the children of women who consumed large amounts of fish and seafood during pregnancy. The NAS Study further concluded that the impact on that population was likely to be sufficient to result in an increase in the number of children who struggle to keep up in school and might require remedial classes or special education.

2. EPA's December 2000 Appropriate and Necessary Finding

On December 20, 2000, EPA issued a finding pursuant to CAA section 112(n)(1)(A) that it was appropriate and necessary to regulate coal- and oil-fired EGUs under section 112 and added such units to the list of source categories subject to regulation under section 112(d). In making that finding, EPA considered the Utility Study, the Mercury Study, the NAS Study, and certain additional information, including information about Hg emissions from coal-fired EGUs that EPA obtained pursuant to an information collection request (ICR) under the authority of section 114 of the CAA. 65 FR 79826-27. EPA collected data on the Hg content of coal from all coal-fired EGUs for the calendar year 1999 and Hg emissions stack test data for certain coal-fired EGUs. 65 FR 79826. EPA also solicited data from the public through a February 29, 2000, notice (65 FR 10783). The public had an opportunity to provide their views on what the section 112(n)(1)(A) appropriate and necessary regulatory finding should be at a public meeting in Chicago, Illinois, on June 13, 2000 (65 FR 18,992). 65 FR 79826.

In the December 2000 notice, EPA explained that it evaluated EGUs based on the type of fossil fuel combusted (*i.e.*, coal, oil, and natural gas). The December 2000 Finding focused primarily on Hg emissions from coal-fired EGUs. Mercury was determined to be the HAP of greatest concern in the Utility Study. In evaluating Hg emissions from coal-fired EGUs, EPA stated that the quality of the Hg data available in 2000 was considerably better than the data available for the Utility Study because of the results of the 1999 ICR. The new data also

corroborated the Hg emissions estimates in the study. 65 FR 79828. In the finding, EPA explained that Hg is highly toxic and persistent and that it bioaccumulates in the food chain; that Hg air emissions from all sources, including EGUs, deposit on the land where the Hg may transform into MeHg, which is the primary type of Hg that accumulates in fish tissue; and that eating Hg contaminated fish was the primary route of exposure for humans. 65 FR 79827. The potential hazard of most concern was determined to be consumption by subsistence fish-eating populations and women of childbearing age because of the adverse effects that Hg poses to the developing fetus. 65 FR 79827. Finally, EPA noted that approximately 7 percent of women of child bearing age were exposed to levels of MeHg that exceeded the RfD. 65 FR 79827.

EPA further estimated that about 60 percent of the total Hg deposited in the U.S. came from anthropogenic air emissions originating in the U.S. and that EGUs contributed approximately 30 percent of those anthropogenic air emissions. 65 FR 79827. Based on the record before the Agency at the time, EPA determined that there was a plausible link between Hg emissions from EGUs and MeHg in fish and that Hg emissions from EGUs were a threat to public health and the environment. 65 FR 79827.

In discussing the non-Hg HAP from coal- and oil-fired EGUs, EPA stated that HAP metals such as As, Cr, Ni, and Cd are of potential concern for carcinogenic effects. 65 FR 79827. EPA acknowledged that the risk assessments conducted for these HAP indicated that cancer risks were not high, but the Agency could not conclude the potential concern for public health was eliminated for those metals. 65 FR 79827. EPA further stated that dioxins, HCl, and HF were of potential

concern and could be evaluated further during the regulatory development process. 65 FR 79827. EPA also concluded that the remaining HAP evaluated in the Utility Study did not appear to be a public health concern, but the Agency noted that there were limited data and uncertainties associated with this conclusion, and we stated that future data collection efforts could identify additional HAP of potential concern. 65 FR 79827.

EPA also explained that, consistent with Congress's direction in section 112(n)(1)(A), we considered the alternative control strategies available to control the HAP emissions that may warrant control. We noted that currently available controls for criteria pollutants would also be effective at controlling the HAP emissions from EGUs. 65 FR 79828.

EPA then made nine specific conclusions based on the information in the record, some of which are summarized above. 65 FR 79829-30. Based on those conclusions, EPA found that it was "appropriate" to regulate HAP emissions from coal- and oil-fired EGUs because EGUs "are the largest domestic source of Hg emissions, and Hg in the environment presents significant hazards to public health and the environment." 65 FR 79830. EPA noted that the NAS Study confirmed EPA's own research concluding that "mercury in the environment presents a significant hazard to public health." 65 FR 79830. EPA explained that it was appropriate to regulate HAP emissions from coal- and oil-fired units because it had identified certain control options that, it anticipated, would effectively reduce HAP from such units. 65 FR 79830. In discussing its findings, EPA also noted that uncertainties remained concerning the extent of the

public health impact from HAP emissions from oil-fired units. 65 FR 79830.

Once EPA determined that it was "appropriate" to regulate coal- and oil-fired EGUs under CAA section 112, EPA next concluded that it was also "necessary" to regulate HAP emissions from such units under section 112 "because the implementation of other requirements under the CAA will not adequately address the serious public health and environmental hazards arising from such emissions identified in the Utility RTC and confirmed by the NAS Study, and which section 112 is intended to address." 65 FR 79830.

For natural gas-fired EGUs, EPA found that regulation of HAP emissions "is not appropriate or necessary because the impacts due to HAP emissions from such units are negligible based on the results of the study documented in the utility RTC." 65 FR 79831.

In light of the positive appropriate and necessary determination, EPA in December 2000 listed coal- and oil-fired EGUs on the section 112(c) source category list. 65 FR 79831.

3. The 2005 Action

On March 29, 2005, EPA issued the Section 112(n) Revision Rule ("2005 Action") that has since been vacated by the DC Circuit Court. In that rule, EPA reversed the December 2000 Finding and concluded that it was neither appropriate nor necessary to regulate coal- and oil-fired EGUs under section 112 and delisted such units from the section 112(c) source category list. 70 FR 15994. EPA took the position that the December 2000 Finding lacked foundation and that new information confirmed that it was not

appropriate or necessary to regulate coal- and oil-fired EGUs under CAA section 112.

In the final rule, EPA provided a detailed interpretation of section 112(n)(1)(A), including the terms "appropriate" and "necessary," as those terms relate to the regulation of EGUs under section 112. In interpreting the statute, EPA recognized that section 112(n)(1)(A) provided no explicit guidance for determining whether regulation of EGUs is appropriate and necessary. As such, EPA concluded that Congress' direction on the Utility Study provided the only guidance about the substance of the appropriate and necessary finding. Accordingly, EPA extrapolated from Congress' description of the Utility Study when interpreting the terms appropriate and necessary.

Among other things, the Agency interpreted the focus on public health in the Utility Study as precluding EPA from considering environmental impacts. 70 FR 15998. EPA also looked at Congress' focus on EGU emissions in the Study and took the position that EPA could only consider hazards to public health that could be traced directly to HAP emissions from EGUs in assessing whether it was appropriate to regulate. EPA declined to consider the potential adverse public health impacts that may occur as the result of the combination of EGU HAP emissions and HAP emissions from other sources. 70 FR 15998.

In making the determination as to whether it was appropriate to regulate, EPA analyzed whether the level of HAP emissions from EGUs remaining after imposition of the requirements of the CAA would result in a hazard to public health. EPA concluded that if the HAP emissions remaining after imposition of the

requirements of the CAA do not pose a hazard to public health, then regulation under section 112 is not appropriate. EPA also maintained that even if it identified a hazard to public health, regulation may still not be "appropriate" based on other relevant factors, such as the cost effectiveness of regulation under section 112. 70 FR 15600.

In the 2005 Action, EPA interpreted the term "necessary" to mean "that it is necessary to regulate EGUs under section 112 only if there are no other authorities available under the CAA that would, if implemented, effectively address the remaining HAP emissions from EGUs." 70 FR 16001.

Applying these interpretations, the Agency stated that it was neither appropriate nor necessary to regulate HAP emissions from EGUs. The Agency took the position that the December 2000 appropriate finding lacked foundation because the finding was overbroad to the extent that it relied on environmental effects. 70 FR 16002. The EPA next stated that the appropriate determination in the December 2000 Finding lacked foundation because EPA did not fully consider the Hg reductions that would result after imposition of the requirements of the CAA and that new information showed that the level of Hg emissions from EGUs remaining after imposition of the requirements of the CAA do not pose a hazard to public health. 70 FR 16003-4. Specifically, EPA pointed to the promulgation of the Clean Air Interstate Rule (CAIR), issued pursuant to CAA section 110(a)(2)(D), and the Clean Air Mercury Rule (CAMR),[8] issued pursuant to

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[8] On May 18, 2005, EPA issued the Clean Air Mercury Rule (CAMR). 70 FR 28606. That rule established standards of

section 111, and, based on modeling, determined that CAIR, and independently CAMR, could be expected to reduce Hg emissions to levels that would not cause a hazard to public health. Therefore, EPA concluded that it was not appropriate to regulate EGUs under section 112. We note that CAMR was vacated by the D.C. Circuit Court in *New Jersey v. EPA*, and that CAIR was remanded to the Agency in *North Carolina v. EPA*, 531 F.3d 896, *modified on reh'g*, 550 F.3d 1176 (DC Cir. 2008).

As to the necessary finding, EPA took the position that the December 2000 Finding was in error because EPA did not, at the time, examine whether there were any CAA provisions other than section 112 that, if implemented, would address any identified hazards to public health from HAP emissions from EGUs. 70 FR 16004. Specifically, EPA stated that the error existed because EPA did not consider CAA sections 110(a)(2)(D) and 111 and that, considering actions under these sections, hazard to public health from EGUs would be reduced. 70 FR 16005.

EPA also determined that it was not appropriate and necessary to regulate coal-fired EGUs on the basis of non-Hg HAP emission or oil-fired EGUs on the basis of Ni and non-Ni HAP. 70 FR 16007.

4. Litigation History

Shortly after issuance of the December 2000 Finding, an industry group challenged that finding in the DC Circuit Court. UARG v. EPA, 2001 WL 936363, No. 01-1074 (DC Cir. July 26, 2001). The DC Circuit Court dismissed the lawsuit holding that it did not

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performance for emissions of mercury from new and existing coal-fired EGUs pursuant to CAA section 111.

have jurisdiction because section 112(e)(4) provides, in pertinent part, that "no action of the Administrator * * * listing a source category or subcategory under subsection (c) of this section shall be a final agency action subject to judicial review, except that any such action may be reviewed under section 7607 of (the CAA) when the Administrator issues emission standards for such pollutant or category." (emphasis added)

Environmental groups, States, and tribes challenged the 2005 Action and CAMR. Among other things, the environmental and state petitioners argued that EPA could not remove EGUs from the section 112(c) source category list without following the requirements of section 112(c)(9).

On February 8, 2008, the DC Circuit Court vacated both the 2005 Action and CAMR. The DC Circuit Court held that EPA failed to comply with the requirements of section 112(c)(9) for delisting source categories. Specifically, the DC Circuit Court held that section 112(c)(9) applies to the removal of "any source category" from the section 112(c) list, including EGUs. The DC Circuit Court rejected the argument that EPA has the inherent authority to correct its mistakes, finding that, by enacting section 112(c)(9), Congress limited EPA's discretion to reverse itself and remove source categories from the section 112(c) list. The DC Circuit Court found that EPA's contrary position would "nullify § 112(c)(9) altogether." *New Jersey*, 517 F.3d at 583. The DC Circuit Court did not reach the merits of petitioners' arguments on CAMR, but vacated CAMR for existing sources because coal-fired EGUs were listed sources under section 112. The DC Circuit Court reasoned that even under EPA's own interpretation of the CAA, regulation of existing

sources' Hg emissions under section 111 was prohibited if those sources were a listed source category under section 112.[9] The DC Circuit Court vacated and remanded CAMR for new sources because it concluded that the assumptions EPA made when issuing CAMR for new sources were no longer accurate (*i.e.*, that there would be no section 112 regulation of EGUs and that the section 111 standards would be accompanied by standards for existing sources). *Id.* at 583-84. Thus, CAMR and the 2005 appropriate and necessary finding became null and void.

On December 18, 2008, several environmental and public health organizations ("Plaintiffs")[10] filed a complaint in the DC District Court (Civ. No. 1:08-cv-02198 (RMC)) alleging that the Agency had failed to perform a nondiscretionary duty under CAA section 304(a)(2), by failing to promulgate final section 112(d) standards for HAP from coal- and oil-fired EGUs by the statutorily mandated deadline, December 20, 2002, 2 years after such sources were listed under section 112(c). EPA settled that litigation. The consent decree resolving the case requires EPA to sign a notice of proposed rulemaking setting forth EPA's proposed section 112(d) emission standards for coal- and oil-

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[9] In CAMR and the 2005 Action, EPA interpreted section 111(d) of the Act as prohibiting the Agency from establishing an existing source standard of performance under section 111(d) for any HAP emitted from a particular source category, if the source category is regulated under section 112.

[10] American Nurses Association, Chesapeake Bay Foundation, Inc., Conservation Law Foundation, Environment America, Environmental Defense Fund, Izaak Walton League of America, Natural Resources Council of Maine, Natural Resources Defense Council, Physicians for Social Responsibility, Sierra Club, The Ohio Environmental Council, and Waterkeeper Alliance, Inc.

fired EGUs by March 16, 2011, and a notice of final rulemaking by November 16, 2011.

III. Appropriate and Necessary Finding

As required by the CAA, we determined in December 2000, and confirm that finding here, that it is appropriate to regulate emissions of Hg and other HAP from EGUs because manmade emissions of those pollutants pose hazards to public health and the environment, and EGUs are the largest or among the largest contributors of many of those HAP. It is necessary to do so for a variety of reasons, including that hazards to public health and the environment from EGUs remain after imposition of the requirements of the CAA.

In this section, we address the Agency's determination that it is appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112. We first provide our interpretation of the critical terms in CAA section 112(n)(1). As shown below, these interpretations are wholly consistent with the CAA and the December 2000 Finding. We then demonstrate that the December 2000 Finding was valid at the time it was made based on the information available to the Agency at that time. Finally, we explain that, although not required, we recently conducted additional technical analyses given that several years have passed since the December 2000 Finding was issued. Those analyses include both a quantitative and qualitative assessment of the hazards to public health and a qualitative analysis of hazards to the environment associated with Hg and non-Hg HAP from EGUs. The analyses confirm that it remains appropriate and necessary today to regulate EGUs under CAA section 112. We also explain why these analyses and the other information currently before

the Agency confirm that regulation of EGUs under section 112 is appropriate and necessary. Accordingly, such units are properly listed pursuant to section 112(c).

A. Regulating EGUs Under CAA Section 112

CAA section 112(n)(1)(A) requires the Agency to regulate EGUs under section 112 "if the Administrator finds such regulation is *appropriate* and *necessary* after considering the results of the [Utility Study]." (emphasis added). Congress did not define the phrase "appropriate and necessary" in section 112(n)(1)(A). Rather, Congress expressly delegated to the Agency the authority to interpret and apply those terms. *See Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837, 843-44 (1984) (the Agency's interpretation of statutory terms is entitled to considerable deference as long as it is a reasonable reading of the statute).

Courts have interpreted the terms "appropriate" and "necessary" in other provisions of the CAA and other statutes, and concluded that those terms convey upon the Agency a wide degree of discretion. *See, e.g., National Association of Clean Air Act Agencies v. EPA*, 489 F.3d 1221, 1229 (DC Cir. 2007) (finding "both explicit and extraordinarily broad" the Administrator's authority under CAA section 231(a)(3) to "issue regulations with such modifications *as he deems appropriate*.") (emphasis in original); *See also Cellular Telecommunications & Internet Association, et al. v. FCC*, 330 F.3d 502, 510 (DC Cir. 2003), (finding that "[c]ourts have frequently interpreted the word necessary' to mean less than absolutely essential, and have explicitly found that a measure may be necessary' even though acceptable alternatives have not been exhausted." (quoting *Natural Res. Def.*

Council v. Thomas, 838 F.2d 1224, 1236 (DC Cir. 1998) (internal quotation marks omitted)).

We evaluate the terms "appropriate" and "necessary" within the statutory context in which they appear to determine the meaning of the words. *See Cellular Telecommunications*, 330 F.3d at 510 (finding that "it is crucial to understand the context in which the word [necessary] is used in order to comprehend its meaning.") (citations omitted). In this case, we look for guidance in section 112 generally, and focus specifically on section 112(n)(1), which addresses EGUs.

1. Statutory Framework for Evaluating EGUs

As explained above, Congress, concerned by the slow pace of EPA's regulation of HAP, "altered section 112 by eliminating much of EPA's discretion in the process." *New Jersey*, 517 F.3d at 578 (citations omitted). We describe above the two-phased approach to standard setting. Also, relevant, however, is that Congress set very strict deadlines for listing source categories and issuing emission standards for such categories. *See e.g.*, Section 112(c)(6), 112(e)(1); *New Jersey*, 517 F.3d at 578 (noting that "EPA was required to list and to regulate, on a prioritized schedule" all categories and subcategories of major and area sources). Thus, in substantially amending section 112 of the CAA in 1990, Congress sought prompt and permanent reductions of HAP emissions from stationary sources—first through technology-based standards, and then further, as necessary, through risk-based standards designed to protect human health and the environment.

Congress' focus on protecting public health and the environment from EGU HAP emissions is reflected in

section 112(n)(1), titled "[e]lectric utility steam generating units." That section directs EPA to evaluate HAP emissions from EGUs. In addition to directing EPA to regulate EGUs under section 112 if it determines that it is appropriate and necessary to do so, section 112(n)(1) requires the completion of three studies related to HAP emissions from EGUs. Those studies include: (1) The Utility Study pursuant to section (n)(1)(A); (2) the Mercury Study pursuant to section (n)(1)(B); and (3) the NIEHS Study (NAS Study) pursuant to section 112(n)(1)(C). [11]

These studies are described above, in detail. In summary, for the Utility Study, Congress required EPA to evaluate the hazards to public health that are reasonably anticipated to occur as the result of EGU emissions following imposition of the requirements of the CAA. Congress also directed EPA to identify alternative control strategies for those HAP that may warrant regulation under section 112.

The Mercury Study required by section 112(n)(1)(B) is both broader and narrower in scope, as compared to the Utility Study. For example, the Mercury Study is narrower in scope, in that it focuses solely on the impacts from Hg emissions, as opposed to all HAP. The Mercury Study is broader in scope, however, in two important respects. First, Congress required EPA to consider environmental effects in addition to health

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[11] As explained above, the NAS Study studied the same issues Congress wanted addressed pursuant to section 112(n)(1)(C) and, because it was conducted five years after the NIEHS study, it was a more comprehensive study accounting for new information not available to NIEHS. Congress directed both studies and wanted EPA to consider the NAS Study before issuing the appropriate and necessary finding so we are reasonably focusing our discussion on the content of the later study.

effects. Second, Congress required the Agency to consider the cumulative effects of Hg from all sources, including EGUs. In considering the cumulative effects of Hg, the Agency was not required to apportion the cause of any adverse effects among the various sources of Hg. Both the Utility and Mercury Studies considered the control technologies available to control Hg emissions, but only the Mercury Study called for the evaluation of the costs of such controls. Section 112(n)(1)(B).

EPA believes that Congress directed the Agency to conduct the Utility Study so that the Agency would understand the hazards to public health posed by HAP emissions from EGUs alone, and consider whether any hazards that were identified would be addressed through imposition of the requirements of the CAA applicable to EGUs at that time. Congress provided EPA an additional year to examine the impacts of EGU emissions of Hg on health and the environment in combination with other sources of Hg emissions.

The NAS Study required by section 112(n)(1)(C), which was due at the same time as the Utility Study, was to focus on Hg only and the adverse human health effects associated with Hg. The statute directed the determination of the threshold level of Hg below which adverse effects to human health are not expected to occur. The statute further directed the determination of the threshold for Hg concentrations in the tissue of fish which may be consumed, including by sensitive populations, without adverse effects to public health. Here, unlike the Utility Study and the Mercury Study, the statute specifically requires an evaluation of the adverse human health effects of Hg on sensitive populations.

The remaining critical element of section 112(n)(1) is the direction to EPA to determine whether it is appropriate and necessary to regulate EGUs under section 112, considering the results of the Utility Study. Although the Utility Study is a condition precedent to making the appropriate and necessary determination, nothing in section 112(n)(1)(A) precludes the Agency from considering other information in making that determination.

Taken together, we believe these provisions provide a framework for the Agency's determination of whether to regulate HAP emissions from EGUs under section 112. Through these provisions, Congress sought a prompt review and evaluation of the hazards to public health and the environment associated with Utility HAP emissions. This prompt consideration of health and environmental impacts is consistent with the strict deadlines Congress imposed in section 112 on all other source categories. *See infra*.

Section 112(n)(1)(B) is direct evidence that Congress was concerned with environmental effects and cumulative impacts of HAP emissions from EGUs and other sources, particularly with regard to the bio-accumulative HAP Hg. Section 112(n)(1)(C) provides further evidence that Congress was concerned with limiting HAP emissions from EGUs to a level that protects sensitive populations. We believe the scope of the Utility Study was limited to HAP emissions from EGUs and hazards to public health, not because Congress was unconcerned with adverse environmental effects or the cumulative impact of HAP emissions, but because the Utility Study, as required, was a significant undertaking in itself and Congress wanted the Agency to complete the study within 3 years. Thus, section 112(n)(1) reveals, among other

things, Congress' concern for the health and environmental effects of HAP emissions from EGUs, both alone and in conjunction with other sources, the impact of Hg emissions from EGUs, and the availability of controls to address HAP emissions from EGUs.

Finally, significantly, nowhere in section 112(n)(1) does Congress require the consideration of costs in assessing health and environmental impacts. The only reference to costs is in section 112(n)(1)(B) and that reference required the Agency to consider the costs of emission reduction controls for Hg.

2. Interpretation of Key Terms

Section 112(n)(1)(A) itself provides no clear standard to govern EPA's analysis and determination of whether it is "appropriate and necessary" to regulate utilities under section 112. The statute simply requires EPA to regulate EGUs under section 112 if it determines that such regulation is appropriate and necessary, after considering the results of the Utility Study. As noted above, courts have interpreted the terms appropriate and necessary as conveying considerable discretion to the Agency in determining what is appropriate and necessary in a given context.

As explained more fully below, in this context, we interpret the statute to require the Agency to find it *appropriate* to regulate EGUs under CAA section 112 if the Agency determines that the emissions of one or more HAP emitted from EGUs pose an identified or potential hazard to public health or the environment at the time the finding is made. If the Agency finds that it is *appropriate* to regulate, it must find it *necessary* to regulate EGUs under section 112 if the

identified or potential hazards to public health or the environment will not be adequately addressed by the imposition of the requirements of the CAA. Moreover, it may be *necessary* to regulate utilities under section 112 for a number of other reasons, including, for example, that section 112 standards will assure permanent reductions in EGU HAP emissions, which cannot be assured based on other requirements of the CAA.

The following subsections describe in detail our interpretation of the key statutory terms. We also explain below how the interpretations set forth in this notice are wholly consistent with the December 2000 Finding. Further, to the extent our interpretation differs from that set forth in the 2005 Action, we explain the basis for that difference and why the interpretation, as set forth in this preamble, is reasonable. *See National Cable & Telecommunications Ass'n, et al. v. Brand X Internet Services, et al.*, 545 U.S. 967, 981 (2005) (Discussing the deference provided to an Agency when changing interpretations the Court stated "change is not invalidating, since the whole point of *Chevron* deference is to leave the discretion provided by ambiguities of a statute with the implementing agency.") (Internal citations and quotations omitted); *See* also *Department of Treasury v. FLRA*, 494 U.S. 922, 933 (1990) (Finding that EPA's judgment should only be overturned if it is deemed unreasonable, not merely because other, reasonable alternatives exist).

a. "Appropriate" To Regulate EGUs

We interpret section 112(n)(1)(A) to require the Agency to find regulation of EGUs under section 112 appropriate if we determine that HAP emissions from EGUs pose a hazard to public health or the

environment at the time the finding is made. The hazard to public health or the environment may be the result of HAP emissions from EGUs alone or the result of HAP emissions from EGUs in conjunction with HAP emissions from other sources. In addition, EPA must find that it is appropriate to regulate EGUs if it determines that any single HAP emitted by utilities poses a hazard to public health or the environment. We further interpret the term "appropriate" to not allow for the consideration of costs in assessing whether HAP emissions from EGUs pose a hazard to public health or the environment. Finally, we may conclude that it is appropriate, in part, to regulate EGUs if we determine that there are controls available to address HAP emissions from EGUs.

i. Basis for Interpretation

As stated above, the appropriate finding may be based on hazards to public health or the environment. Although we believe that Congress' primary concern, as expressed in section 112(n)(1)(A) and 112(n)(1)(C), related to hazards to public health, the inclusion of environmental effects in section 112(n)(1)(B) indicates Congress' interest in protecting the environment from HAP emissions from EGUs as well.

Moreover, the term "appropriate" is extremely broad and nothing in the statute suggests that the Agency should ignore adverse environmental effects in determining whether to regulate EGUs under section 112. Further, had Congress intended to prohibit EPA from considering adverse environmental effects in the "appropriate" finding, it would have stated so expressly. Absent clear direction to the contrary, and considering the purpose of the CAA (*see e.g.*, CAA section 101, 112(c)(9)(B)(ii)), it is reasonable to consider environmental effects in evaluating the

hazards posed by HAP emitted from EGUs when assessing whether regulation of EGUs under section 112 is appropriate. Accordingly, we interpret the statute to authorize the Agency to base the appropriate finding on either hazards to public health or the environment.

We also maintain that the Agency should base its "appropriate" evaluation on the hazards to public health or the environment that exist at the time the determination is made, not after considering the imposition of the other requirements of the CAA. The Agency evaluates whether imposition of the requirements of the CAA will adequately address any identified hazards only in the context of the necessary finding. Thus, in assessing whether regulation of EGUs is appropriate under section 112, we evaluate the current hazards posed by such units, as opposed to projecting what such hazards may look like after imposition of the requirements of the CAA.

We further interpret the CAA as allowing the Agency to base the appropriate finding on hazards to public health or the environment that result from HAP emissions from EGUs alone or hazards to public health and the environment that result from HAP emissions from EGUs in conjunction with HAP emissions from other sources. Section 112(n)(1) does not focus exclusively on EGU-only HAP emissions.

As explained above, section 112(n)(1)(B) and (C) require either expressly or implicitly the consideration of Hg emissions from all sources, not just EGUs. Section 112(n)(1)(B) is of note because that provision does not require the Agency to determine the hazard posed by Hg from EGUs alone. Rather, Congress required EPA to evaluate the health and environmental effects of Hg emissions from "electric

utility steam generating units, municipal waste combustion units, and other sources, including area sources." Section 112(n)(1)(C) is also relevant because it requires a human health-based assessment of the hazards posed by Hg without regard to the origin of the Hg. Congress could have directed an evaluation of the human health risk attributable to EGUs alone, but it did not. Congress also did not require such an assessment be conducted in the NAS Study.

In addition, Congress directed the Agency in section 112(n)(1)(A) to regulate EGUs under section 112 if the results of the Utility Study caused the Agency to conclude that regulation was appropriate and necessary. Section 112(n)(1)(A) is not written in a manner to preclude consideration of other information when determining whether it is appropriate and necessary to regulate EGUs under section 112, and that includes consideration of all hazards, both health and environmental, posed by HAP emitted by EGUs. *See United States v. United Technologies Corp.*, 985 F.2d 1148, 1158 (2d Cir. 1993) ("based upon" does not mean "solely").

Finally, focusing on HAP emissions from EGUs alone when making the appropriate finding ignores the manner in which public health and the environment are affected by air pollution. An individual that suffers adverse health effects as the result of the combined HAP emissions from EGUs and other sources is harmed, irrespective of whether HAP emissions from EGUs alone would cause that harm. For this reason, we believe we may consider the hazards to public health and the environment posed by HAP emissions from EGUs alone or in conjunction with HAP emissions from other sources.

Furthermore, the appropriate finding may be based on a finding that any single HAP emitted from EGUs poses a hazard to public health or the environment. Nothing in section 112(n)(1)(A) suggests that EPA must determine that every HAP emitted by EGUs poses a hazard to public health or the environment before EPA can find it appropriate to regulate EGUs under section 112. Interpreting the statute in this manner would preclude the Agency from addressing under section 112 identified or potential hazards to public health or the environment associated with HAP emissions from EGUs unless we found a hazard existed with respect to each and every HAP emitted.

Indeed, Congress' focus in section 112(n)(1)(B) and (C) on Hg indicates Congress' awareness that Hg was a problem and supports the position that EPA could find it appropriate to regulate EGUs based on the adverse health and environmental effects of a single HAP. Furthermore, the statute does not directly or expressly authorize the Agency to regulate only those HAP for which a hazard finding has been made. In fact, the statute requires the Agency to regulate EGUs under section 112 if the Agency finds regulation under section 112 is appropriate and necessary, and regulation under section 112 for major sources requires MACT standards for *all HAP* emitted from the source category. *See, e.g., National Lime Ass'n v. EPA*, 233 F.3d 625, 633 (DC Cir. 2000). For these reasons, we conclude we must find it appropriate to regulate EGUs under section 112 if we determine that the emissions of any single HAP from such units pose a hazard to public health or the environment.

We also maintain that the better reading of the term "appropriate" is that it does not allow for the consideration of costs in assessing whether hazards to

public health or the environment are reasonably anticipated to occur based on EGU emissions. Had Congress intended to require the Agency to consider costs in assessing hazards to public health or the environment associated with EGU HAP emissions, it would have so stated.

This interpretation is consistent with the overall structure of the CAA. Congress did not authorize the consideration of costs in listing any source categories for regulation under section 112. In addition, Congress did not permit the consideration of costs in evaluating whether a source category could be delisted pursuant to the provisions of section 112(c)(9).

Under section 112(n)(1)(A), EPA is evaluating whether to regulate HAP emissions from EGUs at all. It is reasonable to conclude that costs may not be considered in determining whether to regulate EGUs under section 112 when hazards to public health and the environment are at issue.

Finally, consistent with sections 112(n)(1)(A) and 112(n)(1)(B), we conclude that we may base the appropriate finding on the availability of controls to address HAP emissions from EGUs.

ii. The December 2000 Finding

The Agency's interpretation of the term "appropriate," as set forth above, is wholly consistent with the Agency's appropriate finding in December 2000. As noted above, in 2000, we concluded that it was appropriate to regulate EGUs under section 112 because Hg in the environment posed a hazard to public health and the environment. The Agency also concluded it was appropriate because of uncertainties associated with the hazards posed by other HAP emitted from EGUs. 65 FR 79827. Finally, the EPA

concluded that it was appropriate because of the availability of controls to reduce HAP emissions from EGUs. In making the finding as it related to Hg, the Agency considered the hazards posed by Hg in the environment and the contribution of EGUs to that hazard. In addition, EPA did not consider costs when making the appropriate determination. Further, the appropriate finding evaluated the hazards at the time, as opposed to the hazards remaining after imposition of the requirements of the CAA. EPA evaluated whether the other requirements of the CAA would adequately address the hazards in the necessary prong only.[12]

iii. The 2005 Action

As noted above, in 2005, EPA revised its December 2000 Finding and stated that the appropriate finding: (1) Could not be based on adverse environmental effects; (2) must be made considering only HAP emissions from EGUs; (3) must be made after consideration of the imposition of the requirements of the CAA; and (4) must consider other factors (*e.g.*, costs) even if we determine that HAP emissions from EGUs pose a hazard to public health. This proposal differs from the 2005 Action, and we address each of these differences below.

First, we change the position taken in 2005 that the appropriate finding could not be based on environmental effects alone. In 2005, we did not properly consider all of the provisions of section 112(n)(1). The Agency should not interpret the CAA to

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[12] As explained below, EPA reasonably concluded in December 2000 that it was appropriate and necessary to regulate EGUs under section 112 based on the record before the Agency at that time.

limit the Agency's discretion to protect the environment absent clear direction to that effect. In essence, the Agency's interpretation in 2005 would have required the Agency to ignore a catastrophic environmental harm (*e.g.*, the extinction of a species) if the Agency could not also identify a hazard to public health. EPA took this position regarding environmental effects in 2005 even though in that same rule it correctly interpreted section 112(n)(1)(A) to allow the Agency to consider information beyond the Utility Study in making the appropriate and necessary determination. 70 FR 15,997-99. The 2005 interpretation that EPA cannot consider environmental effects in evaluating whether it is appropriate to regulate EGUs under section 112 was neither reasonable nor consistent with the goals of the CAA, and, therefore, we are rejecting that interpretation and returning to the approach taken in 2000 that allowed consideration of environmental effects.

Second, for all of the reasons stated above, we are revisiting the 2005 interpretation that required the Agency to consider HAP emissions from EGUs without considering the cumulative impacts of all sources of HAP emissions. Nothing in section 112(n)(1)(A) prohibits consideration of HAP emissions from EGUs in conjunction with HAP emissions from other sources of HAP. We believe it is more reasonable to interpret the statute to authorize the Agency to consider the cumulative effects of HAP that are emitted from EGUs and other sources. This interpretation allows the Agency to evaluate more fully whether HAP emissions from EGUs pose a hazard to public health or the environment consistent with the manner in which the public and the environment are exposed to HAP emissions.

Third, we are revising the 2005 interpretation that required the Agency to evaluate the hazards to public health after imposition of the requirements of the CAA. We conclude today that in 2005 the Agency improperly conflated the appropriate finding and the necessary finding by requiring consideration of the ameliorative effects of other CAA requirements in both prongs of the appropriate and necessary finding. We believe the Agency must find it appropriate to regulate EGUs under section 112 if we determine that HAP emitted by EGUs pose a hazard to public health or the environment at the time the finding is made. The issue of how and whether those hazards are reduced after imposition of the requirements of the CAA is an issue for the necessary prong of the finding.

Finally, we are rejecting the 2005 interpretation that authorizes the Agency to consider other factors (*e.g.*, cost), even if the Agency determines that HAP emitted by EGUs pose a hazard to public health (or the environment). We reject the consideration of costs for all the reasons set forth above. Furthermore, the better reading of section 112(n)(1)(A) is that the Agency should find it appropriate to regulate EGUs under section 112 if a hazard to public health or the environment is identified. We think it unreasonable to decline to make the appropriate finding based on any factor, cost or otherwise, if we determine that EGUs pose a hazard to public health or the environment.

b. "Necessary" To Regulate EGUs

Once the Agency has determined that it is appropriate to regulate EGUs under section 112, the Agency must then determine whether it is necessary to regulate EGUs under section 112. As stated above, we have considerable discretion to determine whether regulation of EGUs under section 112 is necessary.

The DC Circuit Court has stated that "there are many situations in which the use of the word necessary,' in context, means something that is done, regardless of whether it is indispensible, to achieve a particular end." *Cellular Telecommunication*, 330 F.3d at 510.

If the Agency concludes that it is appropriate to regulate EGUs, we believe it is necessary to regulate HAP emissions from EGUs if we determine that the imposition of the requirements of the CAA will not sufficiently address the identified hazards to public health or the environment posed by HAP that are emitted from EGUs. We maintain that we must find it necessary based on such a finding even if regulation under section 112 will not fully resolve the identified hazard to public health or the environment.

We may also determine it is necessary to regulate under section 112 if we are uncertain whether the imposition of the other requirements of the CAA will sufficiently address the identified hazards. We may find it necessary to regulate EGUs under section 112 even if we were to conclude, based on reasonable estimations of emissions reductions, that the imposition of the other requirements of the CAA would, or might, significantly reduce the identified hazard, because the only way to guarantee that such reductions will occur at all EGUs and be maintained is through a section 112(d) standard that directly regulates HAP emissions from utilities. Finally, we may also find it necessary to regulate EGUs under section 112 to further the policy goal of supporting international efforts to reduce HAP emissions, including Hg.

i. Necessary After Imposition of the Requirements of the CAA

In the Utility Study, Congress directed the Agency to evaluate the hazards to public health posed by HAP emissions from EGUs remaining after imposition of the requirements of the CAA, and it gave EPA 3 years to complete that Study. We interpret the necessary requirement first in the context of the phrase "after imposition of the requirements of [the CAA]." Section 112(n)(1)(A).

Congress did not define the phrase "after imposition of the requirements of the Act." The plain meaning of the term "requirement" is something that is necessary, or obligatory. *See, e.g.*, Random House Webster's Unabridged Dictionary, Deluxe Edition, 2001. Given that Congress intended the Utility Study to be completed by 1993, it is reasonable to interpret the phrase "after imposition of the requirements of the Act", as requiring the Agency to consider only those requirements that Congress directly imposed on EGUs through the CAA as amended in 1990 and for which EPA could reasonably predict HAP emission reductions at the time of the Utility Study. The most substantial requirement in this regard was the newly enacted ARP.

The purpose of the ARP was to reduce the adverse effects of acid deposition (more commonly known as "acid rain"), by limiting the allowable emissions of SO[2] and NO[X] primarily from EGUs. In enacting the Acid Rain provisions of the Act, Congress explained that the problem of acid deposition was one of "national and international significance," that technologies to reduce the precursors to acid deposition were "economically feasible," and that "control measures to reduce precursor emissions from

steam-electric generating units should be initiated without delay." CAA section 401(a). The ARP also includes a series of very specific emission reduction requirements. For example, the goals of the program include a reduction of annual SO[2] emissions by 10 million tons below 1980 levels and a reduction of NO[X] emissions by two million tons from 1980 levels.

Moreover, the ARP achieved the required reductions by allocating allowances to emit SO[2] at reduced levels to each affected EGU. Sources were prohibited from emitting more SO[2] than the number of allowances held. To comply with these requirements, source owners or operators could elect to install controls, such as scrubbers, switch to lower sulfur fuels at their facilities, or purchase allowances from other EGUs that had reduced their emissions beyond what they were required by the ARP to achieve. It was known at the time of enactment of the 1990 Amendments that the controls used to reduce emissions of SO[2], primarily scrubbers, had the co-benefit of controlling HAP emissions, including Hg emissions. The ARP also included requirements for limiting NO[X] emissions from EGUs. Considering the Acid Rain requirements under section 112(n)(1) is reasonable because the Act contained very specific emission reduction requirements for EGUs, and a tight compliance time-frame. In fact, all of the regulations implementing the SO[2] allowance trading portion of the ARP were completed by the mid-1990's.

The other significant requirement that Congress imposed in the 1990 Amendments was to revise the NSPS for NO[X] emissions from EGUs by 1994. CAA 407(c). However, unlike the SO[2] allowance requirements of the ARP, Congress did not specify the amount of required reductions, but instead directed

EPA to consider the improvements in methods for reducing NO[X] when establishing standards for new sources. Thus, in the 1990 Amendments, Congress sought NO[X] reductions from EGUs both through the ARP and a revision of the NSPS applicable to new sources. The Agency issued these NSPS in 1997.

There are other requirements of Title I of the Act that could affect EGUs, and they include the National Ambient Air Quality Standards (NAAQS). Congress did not impose these provisions directly on EGUs, however. Instead, EPA is responsible for developing the NAAQS, and states are primarily responsible for assuring attainment and maintenance of the NAAQS. For example, EPA stated in the Utility Study that implementation of the 1997 NAAQS for ozone and PM may lead to reductions in Hg emissions, but those potential reductions could not be sufficiently quantified because states have the ultimate responsibility for implementing the NAAQS. See Utility Study, pages ES-25, 1-3, 2-32, 3-14, and 6-15. States use a broad combination of measures (mobile and stationary) to obtain the reductions needed to meet the NAAQS. These decisions are unique to each state, as each state must identify and assess the sources contributing to nonattainment and determine how best to meet the NAAQS. EPA cannot predict with any certainty precisely how states will ensure that the reductions needed to meet the NAAQS will be realized. Moreover, there are additional uncertainties even were a state to impose requirements on EGUs through a State Implementation Plan (SIP), because each EGU may choose to meet the required reductions in a different manner, which could result in more or less HAP emission reductions. Accordingly, we do not believe it would have been appropriate to include such potential emissions reductions in determining

whether it is necessary to regulate HAP emissions from EGUs under section 112.

Further, it is reasonable to interpret the phrase "after imposition of the requirements of the Act", as only requiring consideration of those requirements that Congress directly imposed on EGUs through the CAA as amended in 1990 and for which EPA could reasonably predict emission reductions at the time of the Utility Study. To interpret the phrase otherwise would require the Agency to look ahead two to three decades to forecast what possible requirements might be developed and applied to EGUs under some requirement of the CAA at some point in the future.

Indeed, such an interpretation would be inconsistent with the structure and purpose of section 112. As noted above, Congress gave EPA until 1993 to issue the Utility Study and expected the appropriate and necessary finding would follow shortly thereafter. Congress also required EPA to address HAP emissions rapidly from all source categories. See CAA 112(e), supra. It is reasonable to presume that Congress intended EPA to evaluate the need for EGU HAP controls in light of the requirements imposed upon the industry via the new 1990 requirements. Obviously the central requirement that was new and applied to EGUs was the ARP which would be implemented rapidly following passage of the 1990 amendments to the Act.

Although the above represents a reasonable interpretation of what Congress contemplated the Utility Study would examine with regard to "imposition of the requirements of the Act," we recognize that we have discretion to look beyond the Utility Study in determining whether it is necessary to regulate EGUs under section 112. Given that

several years have passed since the December 2000 Finding, we conducted additional analysis. Although not required, we conducted this analysis to demonstrate that even considering a broad array of diverse requirements, it remains appropriate and necessary to regulate EGUs under section 112.

Specifically, we examined a host of requirements, which in our view, far surpass anything Congress could have contemplated in 1990 we would consider as part of our "necessary" determination. For example, our analysis includes certain state rules regulating criteria pollutants, Federal consent decrees, and settlement agreements for criteria pollutants resolving state-initiated and citizen-initiated enforcement actions.[13] We did not include in our analysis any state-only HAP requirements or voluntary actions to reduce HAP emissions, as those are not requirements of the CAA, and are not required by Federal law to remain applicable.[14]

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[13] In our analysis, we included state requirements and citizen and state settlements associated with criteria pollutants because those requirements may have a basis under the CAA. We did not, however, conduct an analysis to determine whether that was the case in each instance. As such, we believe there may be instances where we should not have considered certain state rules or state and citizen suit settlements in our analysis, because those requirements are based solely in state law and are not required by Federal law.

[14] Although, as explained below, our technical analysis examined impacts projected out to 2016, this is a very conservative approach. Given that two decades have passed since the enactment of the 1990 CAA Amendments, we believe we can find it appropriate and necessary to regulate EGUs under section 112, if we determine EGU HAP emissions pose a hazard to public health and the environment today without considering future HAP emission reductions. Congress could not have contemplated

ii. Necessary Interpretation

If we determine that the imposition of the requirements of the CAA will not address the identified hazards, EPA must find it necessary to regulate EGUs under section 112. Section 112 is the authority Congress provided to address hazards to public health and the environment posed by HAP emissions and section 112(n)(1)(A) requires the Agency to regulate under section 112 if we find regulation is "appropriate and necessary." If we conclude that HAP emissions from EGUs pose a hazard today, such that it is appropriate, and we further conclude based on our scientific and technical expertise that the identified hazards will not be resolved through imposition of the requirements of the CAA, we believe there is no justification in the statute to conclude that it is not necessary to regulate EGUs under section 112.

Furthermore, we believe it is necessary to regulate if we have identified a hazard to public health or the environment that will not be addressed by imposition of the requirements of the CAA even if regulation of EGUs under section 112 will not fully resolve the identified hazard. We conclude that this is particularly true for bio-accumulative HAP such as Hg because EPA can only address such emissions from domestic sources and mitigation of identified risks associated with such HAP is a reasonable goal. *See* section 112(c)(6). EPA cannot decline to find it "necessary" to regulate EGUs under section 112 when it has identified a hazard to public health or the

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in 1990 that EPA would have failed in 2011 to have regulated HAP emissions from EGUs where hazards to public health and the environment remain.

environment, simply because that regulation will not wholly resolve the identified hazards. The statute does not require the Agency to conclude that identified hazards will be fully resolved before it may find regulation under section 112 necessary. *See Massachusetts v. EPA*, 549 U.S. 497, 525 (2007).

In addition, we may determine it is necessary to regulate under section 112 even if we are uncertain whether the imposition of the requirements of the CAA will address the identified hazards. Congress left it to EPA to determine whether regulation of EGUs under section 112 is necessary. We believe it is reasonable to err on the side of regulation of such highly toxic pollutants in the face of uncertainty. Further, if we are unsure whether the other requirements of the CAA will address an identified hazard, it is reasonable to exercise our discretion in a manner that assures adequate protection of public health and the environment. Moreover, we must be particularly mindful of CAA regulations we include in our modeled estimates of future emissions if they are not final or are still subject to judicial review *(i.e.*, the Transport Rule[15]). If such rules are either not finalized or upheld by the Courts, the level of risk would potentially increase.

We also may find it necessary to regulate EGUs under section 112 even if we conclude, based on reasonable estimations of emissions reductions, that the imposition of the other requirements of the CAA will significantly reduce the identified hazard. We maintain this is reasonable because the only way to

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[15] Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone. Proposed Rule. August 2, 2010. 75 FR 45,210.

guarantee that the necessary reductions in HAP emissions will occur at all EGUs and be maintained is through a section 112(d) standard that directly regulates HAP emissions from EGUs. This is true because sources could discontinue use of controls for criteria pollutants that achieve HAP reductions as a co-benefit if new control technologies or practices are identified that reduce the relevant criteria pollutants but do not also reduce HAP. For example, scrubbers are often used to reduce SO[2] emissions and those scrubbers also reduce emissions of several HAP. However, if an EGU with a scrubber started complying with its SO[2] standard by switching to low sulfur coal or purchasing allowances, the HAP emission reduction co-benefits associated with the scrubber would no longer be realized. In addition, at the time Congress passed the 1990 CAA amendments, there were many older EGUs that had few or no controls in place. Over 20 years later, there remain a significant number of older EGUs that are only minimally controlled. The Agency may find it necessary to regulate EGUs under section 112 to ensure that these minimally controlled EGUs and those units that switch to other criteria pollutant compliance options, thereby no longer achieving the same HAP reductions, are subject to HAP regulation, such that the estimated reductions in the identified hazards are realized.

iii. December 2000 Finding

Our interpretation of the necessary finding is reasonable and consistent with the December 2000 Finding. In that finding, EPA determined that the imposition of the requirements of the CAA would not address the serious public health and environmental hazards resulting from EGU HAP emissions. We also stated that section 112 is the authority to address

hazards from HAP emissions. Because we determined that the imposition of the requirements of the CAA would not address the identified hazards, we correctly concluded it was necessary to regulate under section 112. Although the Agency did not expressly interpret the term necessary in the December 2000 Finding, under the interpretation set forth above, the Agency must find it necessary if we conclude that the imposition of the other requirements of the CAA will not address the identified hazards. Because EPA reached that conclusion, the Agency correctly determined that it was necessary to regulate EGU HAP emissions and did not need to base the 2000 necessary finding on any of the other bases set forth above.

iv. The 2005 Action

We stated in 2005 that "it is necessary to regulate EGUs under section 112 only if there are no other authorities under the CAA that, if implemented, would effectively address the remaining HAP emissions from EGUs." 70 FR 16,001.[16] In essence, we stated in 2005 that section 112(n)(1)(A) requires the Agency to scour the CAA to determine whether there is a direct or indirect manner in which EPA could regulate HAP emissions from EGUs, notwithstanding the fact that Congress expressly provided section 112

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[16] In the rule reconsidering the 2005 Action, we further clarified that in evaluating the effectiveness of other CAA authorities we considered whether those other authorities could be implemented in a cost-effective and administratively effective manner. 71 FR 33,391. We need not address this in detail because we conclude that the threshold conclusion that the Agency must look for alternative CAA authorities that could be used to regulate HAP emissions from EGUs before finding it necessary is invalid.

for the purpose of regulating HAP emissions from stationary sources. This interpretation is not reasonable.

Congress enacted section 112 for the express purpose of regulating HAP emissions. It is not reasonable to interpret section 112(n)(1)(A) to require the Agency to find another provision of the CAA to address identified hazards to public health or the environment. This is particularly the case where the Agency would not have certainty that such alternative legal theory would withstand judicial scrutiny because section 112 is the authority expressly provided to regulate HAP emissions and no other provision provides express authority to regulate HAP emissions from existing stationary sources.[17] Although anyone can challenge the substance of a section 112 standard, no one can challenge that regulation of HAP emissions under section 112 is proper for validly listed source categories.

Furthermore, section 112(n)(1)(A) states explicitly that the Agency shall regulate EGUs "under this section" if the Agency determines it is "appropriate and necessary after considering the results of the (Utility Study)." We reiterate that the only precondition to regulating EGUs is consideration of the results of the Utility Study. We believe it is unreasonable to argue that Congress directed the Agency as part of the Utility Study to scour the CAA for alternative legal authorities for regulating HAP emissions, either directly or indirectly. Indeed, the Agency did not interpret the requirement in section 112(n)(1)(A) to conduct the study in that manner, as

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[17] In theory, an NSPS is legally permissible for new stationary sources of HAP.

evidenced by the Utility Study itself. Absent that interpretation, we think it is unreasonable to conclude that the Agency must undertake such an effort to make the necessary finding because Congress authorized the Agency to base the "appropriate and necessary" finding on the Utility Study alone.

For all the reasons above, we believe it is appropriate to regulate EGUs under section 112 if the Agency determines that HAP emissions from such units pose a hazard to public health or the environment at the time of the finding, and it is necessary to regulate EGUs under section 112 if the imposition of the other requirements of the CAA will not adequately address the identified hazards to public health or the environment, or there are other compelling reasons making it necessary to regulate HAP emissions from EGUs under section 112.

c. Hazards to Public Health or the Environment

Section 112(n)(1)(A) neither defines the phrase "hazards to public health," nor sets forth parameters for EPA to use in determining whether HAP emissions from EGUs pose a hazard to public health. The phrase is also not defined elsewhere in the CAA. EPA, therefore, has broad discretion, using its technical and scientific expertise, to determine whether HAP emissions from EGUs pose a hazard to public health.

In evaluating hazards to the environment, however, Congress did provide some direction. Specifically, it defined the term "adverse environmental effects" in section 112(a)(7), and as explained further below, we evaluate hazards to the environment consistent with that definition.

Because Congress did not define "hazard to public health" the Agency must use its scientific and

technical expertise to determine what constitutes a hazard to public health in the context of EGU HAP emissions. The Agency considers various factors in evaluating hazards to public health, including, but not limited to, the nature and severity of the health effects associated with exposure to HAP emissions; the degree of confidence in our knowledge of those health effects; the size and characteristics of the populations affected by exposures to HAP emissions; the magnitude and breadth of the exposures and risks posed by HAP emissions from a particular source category, including how those exposures contribute to risk in populations with additional exposures to HAP from other sources; and the proportion of the population exposed above benchmark levels of concern (*e.g.*, cancer risks greater than 1 in a million or non-cancer effects with a hazard quotient (HQ) greater than 1). See Section III(D) below for a discussion of the Agency's technical conclusions as to whether a hazard to public health or the environment exists based on the facts at issue here.

Although Congress provided no definition of hazard to public health, section 112(c)(9)(B) is instructive. In that section, Congress set forth a test for removing source categories from the section 112(c) source category list. That test is relevant because it reflects Congress' view as to the level of health effects associated with HAP emissions that Congress thought warranted continued regulation under section 112. The Agency finds section 112(c)(9)(B)(i) particularly instructive because it provides a numerical threshold for HAP that may cause cancer. Specifically, that provision provides that EPA may delete a source category from the section 112(c) list if no source in the category emits such HAP in quantities which may cause a lifetime risk of cancer *greater than one in one*

million to the individual in the population who is most exposed to such HAP emissions. Thus, the Agency reads section 112(c)(9)(B)(i) to reflect Congress' view of the acceptable hazard to public health for HAP that may cause cancer.

Congress defined the phrase "adverse environmental effect" in section 112(a)(7) to mean "any significant and widespread adverse effect, which may reasonably be anticipated, to wildlife, aquatic life, or other natural resources, including adverse impacts on populations of endangered or threatened species or significant degradation of environmental quality over broad areas."

Section 112(n)(1)(B) required EPA to examine the environmental effects of Hg emissions. Because Congress defined the term "adverse environmental effect" in section 112(a)(7), we believe that such definition should guide our assessment of whether hazards to the environment posed by Utility HAP emissions exist. As with hazards to public health, however, the Agency must use its discretion to determine whether the adverse environmental effects identified warrant a finding that it is appropriate to regulate HAP emissions from EGUs based on those effects. In evaluating the environmental effects, we have stated that we may consider various aspects of pollutant exposure, including: "[t]oxicity effects from acute and chronic exposures" expected from the source category (as measured or modeled); "persistence in the environment;" "local and long-range transport;" and "tendency for bio-magnification with toxic effects manifest at higher trophic levels." 67 FR 44,718 (July 3, 2002).

In interpreting the term itself, we believe the broad language in section 112(a)(7) referring to "any"

enumerated effect "which may be reasonably anticipated" evinces Congressional intent to not restrict the scope of that term to only certain specific impacts. 62 FR 36440 (July 7, 1997); 63 FR 14094 (March 24, 1998). Further, the section 112(a)(7) reference to "any" enumerated effect in the singular clearly contemplates impacts of limited geographic scope, suggesting that the "widespread" criterion does not present a particularly difficult threshold to cross. *Id.* This is further supported by the fact that section 112(a)(7) provides as an example of adverse environmental effects, adverse impacts on populations of endangered or threatened species, which as reflective of their imperiled status are especially likely to exist in limited geographic areas. EPA believes that the "widespread" criterion would not exclude impacts that might occur in only one region of the country. *Id.*

d. Regulating EGUs "Under This Section"

The statute directs the Agency to regulate EGUs under section 112 if the Agency finds such regulation is appropriate and necessary. Once the appropriate and necessary finding is made, EGUs are subject to section 112 in the same manner as other sources of HAP emissions. Section 112(n)(1)(A) provision provides, in part, that:

[t]he Administrator shall perform a study of the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units of pollutants listed *under subsection (b) of this section* after imposition of the requirements of this chapter * * * The Administrator shall regulate electric utility steam generating units *under this section*, if the Administrator finds such regulation is

appropriate and necessary after considering the results of the study required by *this subparagraph*.

Emphasis added.

In the first sentence, Congress described the study and directed the Agency to evaluate the hazards to public health posed by HAP emissions listed *under subsection* (b) (*i.e.*, section 112(b)). The last sentence requires the Agency to regulate under this section (*i.e.*, section 112) if the Agency finds such regulation is appropriate and necessary after considering the results of the study required by *this subparagraph* (*i.e.*, section 112(n)(1)(A)). The use of the terms section, subsection, and subparagraph demonstrates that Congress was consciously distinguishing the various provisions of section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs if the Agency finds it appropriate and necessary to do so. Congress directed the Agency to regulate utilities "under this section," and accordingly EGUs should be regulated in the same manner as other categories for which the statute requires regulation.

Furthermore, the DC Circuit Court has already held that section 112(n)(1) "governs how the Administrator decides whether to list EGUs" and that once listed, EGUs are subject to the requirements of section 112. *New Jersey*, 517 F.3d at 583. Indeed, the DC Circuit Court expressly noted that "where Congress wished to exempt EGUs from specific requirements of section 112, it said so explicitly," noting that "section 112(c)(6) expressly exempts EGUs from the strict deadlines imposed on other sources of certain pollutants." *Id.* Congress did not exempt EGUs from the other requirements of section 112, and once listed, EPA is required to establish emission standards for EGUs

consistent with the requirements set forth in section 112(d), as described above.

EPA requests comment on section III.A.

B. The December 2000 Appropriate and Necessary Finding was Reasonable

EPA reasonably determined in December 2000 that it was appropriate and necessary to regulate HAP emissions from EGUs under CAA section 112. In making that finding, EPA considered all of the information that Congress had identified as most salient, including the Utility Study, the Mercury Study, and the information in the NAS Study.[18] EPA even conducted an ICR soliciting emissions information on Hg, which was the HAP of most concern to Congress, as evidenced by section 112(n)(1). EPA collaborated further with a number of other entities and Federal Agencies, including the U.S. Department of Energy (DOE). EPA carefully evaluated all of this information, much of which had been the subject of extensive peer review, and reasonably determined, on the record before the Agency at the time, that it was appropriate and necessary to regulate EGUs under section 112.

1. EPA Appropriately Based the Finding on the Information Required by Section 112(n)(1) and Reasonably Made the Finding Once It Had Completed the Required Studies

In making the appropriate and necessary finding in 2000, EPA considered all of the relevant information in the three Studies required by section 112(n)(1) and

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[18] As explained above, we discuss the NAS Study here because it addressed the same issues as the NIEHS study, and it is the more recent study.

the NAS Study. 65 FR 79826-27. The Utility, Mercury, and NAS Studies together consisted of thousands of pages of information and technical analyses. All of these studies were peer reviewed prior to issuance. In fact, the Mercury Study was reviewed by over 65 independent scientists.[19] The NAS Study contains a thorough technical discussion summarizing the state of the science at the time regarding the human health effects of MeHg.

In addition to conducting the studies that Congress required, EPA collected relevant information on Hg emissions and available control technologies. Specifically, pursuant to a CAA section 114 ICR, EPA collected data on the Hg content in coal from all coal-fired EGUs for calendar year 1999. Through the 1999 ICR, EPA also obtained stack test data for certain coal-fired EGUs to verify Hg emissions estimates for the EGU source category. 65 FR 79826. EPA further solicited data from the public through a February 29, 2000, notice (65 FR 10,783), and provided the public an opportunity to provide its views on what the regulatory finding should be at a public meeting. 65 FR 79826 (citing 65 FR 18992). Finally, EPA undertook an evaluation of the Hg control performance of various emission control technologies that were either currently in use on EGUs or that could be applied to such units for Hg control. EPA conducted this evaluation with other parties, including the DOE. 65 FR 79826. EPA also evaluated other emission control approaches that would reduce EGU HAP emissions. *Id.* at 79827-29.

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[19] Mercury Study Report to Congress, Vol. I, Pg. 6, December 1997.

Although Congress did not provide a deadline by which EPA must issue the appropriate and necessary finding, the deadlines Congress provided for completion of the required studies signal that Congress wanted EPA to make the appropriate and necessary finding shortly after completion of the studies. Congress required that the Utility Study and NIEHS Study be submitted by November 15, 1993, and the Mercury Study by November 15, 1994. We reasonably conclude based on the timing of the studies that Congress wanted the Agency to evaluate the hazards to public health and the environment associated with HAP emissions from EGUs as quickly as possible and take steps to regulate such units under section 112 if hazards were identified.

Congress later provided a direct signal as to the timing of the appropriate and necessary finding in the committee report associated with EPA's fiscal year 1999 appropriations bill, which directed the Agency to fund the NAS Study. In that report, Congress indicated that it did not want the Agency to make the appropriate and necessary finding for Hg until the NAS study was completed. *See* H.R. Conf. Rep. No 105-769, at 281-282 (1998).[20]

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[20] This direction is consistent with section 112(n)(1). As noted above, the Utility Study was the only condition precedent to making the appropriate and necessary finding. The NIEHS study called for by 112(n)(1)(C) was to have been completed at the same time as the Utility Study. As such, Congress had originally contemplated that both the Utility and NIEHS studies would be available at the time the Agency made the appropriate and necessary finding. The NAS study considered the same information required in the NIEHS study so the Congressional direction in the fiscal year 1999 appropriation is consistent with the original drafting of section 112(n)(1).

After considering all of the information that Congress considered most relevant, including the NAS Study that was issued in June 2000, EPA determined that it was appropriate and necessary to regulate EGUs under section 112 and listed such units for regulation on December 20, 2000. As explained below, the Agency acted reasonably in issuing the finding at that time because of the identified and potential hazards to public health and the environment associated with HAP emissions from utilities, which the Agency concluded would not be addressed through imposition of the requirements of the CAA. It would not have been reasonable to delay the finding to collect additional information given the considerable delay in completion of the required studies and the hazards to public health and the environment identified as of December 2000.

2. EPA Reasonably Concluded in December 2000 That It Was Appropriate To Regulate EGUs Under Section 112

The December 2000 Finding that it was appropriate to regulate EGUs under section 112 focused largely on hazards to public health and the environment associated with Hg emissions. EPA reasonably focused on this pollutant given that Hg is a persistent, bioaccumulative pollutant that causes serious neurotoxic effects. Indeed, Congress specifically identified this pollutant as one of concern and required two separate studies to be conducted regarding Hg emissions. See Section 112(n)(1)(B) and (C). The information before the Agency in 2000 concerning Hg was both well-documented and scientifically supported. Based on all of the information before it, the Agency concluded that Hg emissions from EGUs posed a hazard to public health. It was also reasonable

for the Agency to find regulation of EGUs appropriate given the uncertainties regarding the extent of public health impacts posed by non-Hg HAP. Finally, it was reasonable to base the appropriate finding on the availability of controls for HAP emissions from EGUs.

a. The Agency Reasonably Concluded It Was Appropriate To Regulate EGUs Based on Hg Emissions

By 2000, the Agency had amassed "a truly vast amount of data" on Hg. See October 10, 1997, letter (page 2) submitting Science Advisory Board (SAB) peer review recommendations on draft Mercury Study.[21] Those data confirmed the hazards to public health and the environment associated with Hg. The data also helped EPA identify the populations of most concern with regard to MeHg exposure. *See* CAA 112(n)(1)(C). Finally, the data showed that EGUs were the largest unregulated source of Hg emissions in the U.S., and that EGUs were projected to increase their Hg emissions to approximately 60 tons in 2010.

We discuss below the central pieces of data and information concerning Hg that formed the basis of our conclusion that Hg posed a threat to public health and the environment.[22] These conclusions were largely drawn from the Mercury Study, which, as noted above, was reviewed by over 65 peer reviewers. Upon reviewing the draft report, the SAB noted that the "major findings of the draft report are well supported by the scientific evidence." In direct response to the SAB review, the Agency conducted additional,

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[21] http://yosemite.epa.gov/sab/SABPRODUCT.nsf/FF2962529C7B158A852571AE00648B72/$ File/ehc9801.pdf.

[22] The central conclusions underlying the 2000 finding are described in detail in the 2000 notice, at 65 FR 79829-30.

comprehensive analyses addressing SAB's recommendations. Thus, in 2000, the Agency had before it a comprehensive record concerning Hg emissions, including the best available science on Hg at the time.

i. Key Facts: Impacts of Hg on Health and the Environment

EPA first concluded that Hg from EGUs was the HAP of greatest concern. *Id.* at 79827. The Agency explained that "mercury is highly toxic, persistent, and bioaccumulates in food chains;" that Hg deposited on land and water can then be metabolized by microorganisms into MeHg; that MeHg is "a highly toxic, more bioavailable, form that biomagnifies in the aquatic food chain (*e.g.*, fish);" and that nearly all of the Hg in fish is MeHg. 65 FR 79827. The Agency further noted that fish consumption is the primary route of exposure for humans and wildlife, and, by July 2000, 40 states and America Samoa had issued fish advisories for Hg, with 13 of those states issuing advisories for all the water bodies in their state. 65 FR 79827. Finally, the Agency explained that neurotoxicity is the health effect of greatest concern with MeHg exposure, and that exposures to MeHg can have serious toxicological effects on wildlife as well as humans.

EPA recognized that increased Hg deposition would lead to increased levels of MeHg in fish and such "increased levels in fish [would] * * * lead to toxicity in fish-eating birds and mammals, including humans." 65 FR 79830. EPA agreed with the NAS that "the long term goal needs to be the reduction in the concentrations of methylmercury in fish" and concluded that reducing Hg emissions from EGUs was

"an important step toward achieving that goal." 65 FR 79830.

The Agency then identified the most affected populations. Specifically, the Agency concluded that women of childbearing age are the population of greatest concern because the developing fetus is the most sensitive to the effects of MeHg. 65 FR 79827. EPA estimated that at that time, 7 percent of women of childbearing age (or about 4,000,000 women) in the continental U.S. were exposed to MeHg at levels that exceeded the RfD and that about 1 percent of women of childbearing age (or about 580,000 women) had MeHg exposures 3 to 4 times the RfD. 65 FR 79827.

The NAS Study affirmed EPA's assessment of the toxicity of MeHg and that the RfD EPA had developed for MeHg was valid. 65 FR 79827. The Agency acknowledged that there was uncertainty with risk at exposure above the RfD, but indicated that risk increased with increased exposure. 65 FR 79827. In addition to focusing on women of childbearing age and developing fetuses, EPA stated a particular concern for subsistence fish-eating populations due to their regular and frequent consumption of relatively large quantities of fish. 65 FR 79830.

As for environmental effects, the Agency observed adverse effects to avian species and wildlife in laboratory studies at levels corresponding to fish tissue MeHg concentrations that are exceeded by a significant percentage of fish sampled in lake surveys. 65 FR 79830. The Agency explained that wildlife consume fish from a more localized geographic area than humans, which can result in elevated levels of Hg in certain fish eating species. Those species include, for example, the kingfisher and some endangered species, such as the Florida panther. 65 FR 79830.

In summary, in the December 2000 Finding, EPA identified Hg in the environment as a hazard to public health and the environment, determined that a significant segment of the most sensitive members of the population were exposed to MeHg at levels exceeding the RfD, and confirmed that the RfD was valid.

ii. EGU Emissions of Hg

In the 2000 finding, the Agency estimated that about 60 percent of the total Hg deposited in the U.S. came from U.S. anthropogenic air emission sources. 65 FR 79827. The Agency stated that the remainder of the Hg deposited in the U.S. was from natural emission sources, reemissions of historic global anthropogenic Hg releases, and non-domestic anthropogenic sources of Hg. 65 FR 79827. EPA identified coal combustion and waste incineration as the source categories likely to bear the greatest responsibility for direct anthropogenic Hg deposition in the continental U.S. 65 FR 79827. EPA further explained that EGUs are the largest unregulated domestic source of Hg emissions, accounting for approximately 30 percent of the current anthropogenic air emissions from domestic sources. 65 FR 79827. These numbers, taken together, reveal that EGUs accounted for approximately 18 percent of the total Hg deposition in the U.S on an annual basis, considering all U.S. anthropogenic sources, natural emission sources, reemissions of historic global anthropogenic Hg releases, and non-domestic anthropogenic sources of Hg.[23]

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[23] n23 EPA estimated that U.S. anthropogenic air emissions of mercury accounted for 60 percent of total deposition in the U.S. and U.S. EGUs accounted for 30 percent of that deposited

In 2000, the Agency also found a plausible link between domestic anthropogenic Hg emissions and MeHg in fish. 65 FR 79829. The Agency explained that although that link could not be estimated quantitatively at the time, the facts before the Agency were sufficient for it to conclude that EGU Hg emissions posed a hazard to public health. Id. at 79830. Those facts included, for example, the link between coal consumption and Hg emissions, EGUs being the largest domestic source of Hg, and certain segments of the population being at risk for adverse health effects due to consumption of contaminated fish. *Id.*

iii. EPA's Conclusions Regarding Hg

Based on the foregoing and all of the information set forth in the December 20, 2000, notice, the Agency found that Hg emissions from EGUs posed a hazard to public health and the environment. In making this finding, the Agency focused on the significant adverse health effects associated with MeHg and the persons most adversely impacted by Hg. The populations most affected were women of childbearing years and their developing fetuses and subsistence fishers. The Agency viewed the adverse health effects and environmental effects described above in conjunction with the then current Hg emissions information provided by EGUs in response to the 1999 ICR. Based on that information, EPA concluded that EGUs accounted for approximately 30 percent of the U.S. anthropogenic emissions of Hg, which translated into about 18 percent of the total Hg deposition in the U.S.

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mercury. Thirty percent of the 60 percent contribution is equal to approximately 18 percent of the total deposition. See Utility Study, page 7-28.

at that time. EPA also knew that Hg from EGUs comprised an undetermined amount of the reemissions of Hg. *See* Mercury Study, Volume 3, page 2-3.

At the time of the December 2000 Finding, the Agency had issued section 112 or 129 standards for several of the other source categories that were significant Hg emitters, and the Agency was required by the CAA to establish section 112 or 129 standards for the other significant Hg emitters. *See* Standards for Large Municipal Waste Combustors, 40 CFR part 60, subpart Ea (NSPS), 56 FR 5507 (February 11, 1991), as amended, and 40 CFR part 60, subpart Eb (Emissions Guidelines), 60 FR 65419 (December 19, 1995), as amended; Standards for Medical Waste Incinerators, 40 CFR part 60, subpart Ec (NSPS), 62 FR 48382 (September 15, 1997), as amended, and 40 CFR part 60, subpart Ce (Emission Guidelines), 62 FR 48379 (September 15, 1997); Standards for Hazardous Waste Combustors, 40 CFR part 63, subpart EEE, 64 FR 53038 (September 30, 1999); Standards for Small Municipal Waste Combustors, 40 CFR part 60, subpart AAAA (NSPS), 65 FR 76355 (December 6, 2000), and 40 CFR part 60, subpart BBBB (Emissions Guidelines), 65 FR 76384 (December 6, 2000); and standard for Portland cement manufacturers (40 CFR part 63, subpart LLL, 64 FR 31925 (June 14, 1999)).[24]

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[24] The NESHAP for Portland cement did not include a standard for Hg when initially promulgated. In *National Lime Ass'n v. EPA*, the DC Circuit Court held that section 112(d) contains a clear statutory directive to regulate all HAP emitted from a listed source category. 233 F.3d 624, 634 (DC Cir. 2000). EPA recently issued final section 112 standards for Portland cement manufacturers, including a standard for Hg emissions from such sources.

Most of these categories emitted far less Hg than EGUs at the time of the finding. Thus, at the time EPA made the December 2000 Finding, the record reflected that Hg posed hazards to public health and the environment, that EGUs were the single largest unregulated domestic source of Hg emissions, and that HAP emissions from EGUs would remain unregulated absent listing under section 112. EPA reasonably found at the time that reducing Hg emissions from EGUs would further the goal of mitigating the hazards to public health and the environment posed by Hg.

EPA also reasonably predicted that incremental reductions in Hg emissions, including from EGUs, would lead to incremental reductions in the MeHg concentration in fish tissue, and that such reductions would, in turn, reduce the risk to public health and the environment. 65 FR 79830. The Mercury Study recognized that Hg is a metal that remains in the environment permanently and can circulate continuously through various environmental media. Although EPA was aware that reductions of Hg from anthropogenic sources may not lead to immediate reductions in fish tissue levels, such reductions would nonetheless serve the long-term goal of reducing the mobilization of Hg to the atmosphere and thus reduce MeHg concentrations in fish.

EPA, therefore, reasonably determined based on the facts that existed at the time that regulation of EGUs was appropriate in order to reduce the hazards to public health and the environment associated with the Hg emissions from EGUs. EPA expressly acknowledged that there were uncertainties concerning the extent of the risk due to Hg emissions from EGUs, because the Agency had not quantified the amount of MeHg in fish that was directly attributable

to EGUs compared to other sources of MeHg. 65 FR 79827. That EPA did not quantify in 2000 the amount of MeHg in fish due to EGUs did not preclude EPA from making an "appropriate" finding. Nowhere in section 112(n)(1) or in its direction concerning the NAS Study did Congress require EPA to quantify the amount of MeHg in fish tissue that was directly attributable to EGUs.[25] Moreover, EPA did not have sufficient confidence in its modeling tools at the time to draw conclusions about the contribution of specific source types to fish MeHg concentrations in specific geographic areas or nationally. These uncertainties are well described in the Utility, Mercury, and NAS Studies.

In any event, in light of the breadth of the scientific evidence before the Agency and the conclusions the Agency reached, it would not have been reasonable to delay the finding to develop an analytical tool to apportion the Hg in fish. The Hg problem at the time was well documented, and the fact that EGUs represented such a significant portion of the Hg

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[25] Consistent with section 112(n)(1), none of the studies addressed the amount of MeHg in fish attributable solely to EGUs. Instead, in the Utility and Mercury Studies, EPA discussed the significant contribution EGUs made to Hg deposition and that Hg deposition was problematic from a health and environmental standpoint. EPA submitted both the Utility Study and the Mercury Study to Congress by 1998. Aware of these studies, Congress, when directing the additional NAS Study, still did not require EPA to determine the amount of MeHg in fish due solely to EGUs. In light of this fact and the broad discretion Congress gave EPA to determine whether it was appropriate or necessary to regulate EGUs under section 112, EPA acted reasonably in 2000 by not delaying its finding several years to conduct an analysis of the portion of MeHg in fish due solely to EGUs.

deposition in the U.S. was ample evidence that it was appropriate to regulate emissions from EGUs—the single largest unregulated domestic source of Hg emissions. 65 FR 79827.

Finally, the Agency had already delayed in completing the section 112(n)(1) studies. Additional delay would have been unreasonable because of the persistence of Hg in the environment and its tendency to bioaccumulate up the food chain, both aspects of Hg in the environment that make it critical to limit additional releases to the environment as quickly as possible. In addition, delay would have been unreasonable because EPA estimated at that time that about 7 percent of women of child-bearing age, one of the most at-risk populations, was exposed to Hg at levels exceeding the RfD, and EPA knew that as the level of exposure above the RfD increased, the level of risk and the extent and severity of adverse effects increased. Thus, EPA reasonably made the appropriate and necessary determination in 2000 to ensure that the largest unregulated domestic source of Hg would be required to install controls, thereby achieving an incremental reduction in the risk associated with a persistent, bioaccumulative HAP.

b. The Appropriate Finding for Non-Hg HAP Was Reasonable

The December 2000 Finding was also reasonable as it pertained to the non-Hg HAP emitted from EGUs. The Agency found it was appropriate to regulate EGUs based on the potential human health concerns from non-Hg HAP, particularly Ni from oil-fired EGUs, and the uncertainties regarding the public health impact of emissions of such HAP. 65 FR 79830. Based on the information in the Utility Study, EPA could not

conclude based on the available information that the non-Hg HAP posed no hazards to public health.

Specifically, the Agency noted that several non-Hg HAP metals, including As, Cr, Ni, and Cd, were of potential concern for carcinogenic effects. 65 FR 79827. EPA acknowledged that the risks did not appear high, but it stated that the risks were not sufficiently low to disregard the metals as a potential concern for public health. 65 FR 79827; *See* Utility Study, Table 5-4, page 5-9 (finding cancer risks from oil-fired EGUs alone for Ni exceeded 1 in a million). The Agency also indicated that dioxins, HCl, and HF were of potential concern and might be evaluated further. 65 FR 79827.

EPA did not view the risks associated with non-Hg HAP in a vacuum. Rather, EPA considered the threat to public health, including uncertainties, associated with both Hg and non-Hg HAP emissions from EGUs in determining whether it was appropriate to regulate such units under section 112.

Finally, even looking solely at non-Hg HAP, EPA's conclusions support regulation of EGUs under section 112. Although Congress provided no metric for the hazard to public health determination, section 112(c)(9) is instructive. Specifically, in that section, Congress set forth a test for removing source categories from the section 112(c) source category list. That test is relevant because it reflects Congress' view as to the level of health effects associated with HAP emissions that Congress thought warranted regulation under section 112. If a source category failed to meet that test, it would remain subject to the requirements of CAA section 112. Thus, CAA section 112(c)(9) can be read to reflect Congress' view of what adverse public health effects from HAP emissions are

acceptable and thus do not warrant regulation under CAA section 112.

For carcinogens, which are at issue here, section 112(c)(9)(B)(i) provides that EPA may delete a source category from the section 112(c) list if no source in the category (or group of sources in the case of area sources) emits such HAP in quantities that may cause a lifetime risk of cancer greater than one in one million to the individual in the population who is most exposed to emissions of such pollutants from the source (or group of sources in the case of area sources). Thus, section 112(c)(9)(B)(i) prohibits the Agency from delisting a major source category from the section 112(c) list if any single source within that category emits cancer causing HAP at levels that may cause a lifetime cancer risk greater than one in one million to the most exposed individual. The Utility Study demonstrated that there were EGUs whose emissions resulted in a cancer risk greater than one in one million. Accordingly, it was reasonable to conclude at the time that non-Hg HAP emissions were of sufficient concern from a health perspective to warrant regulation.

3. EPA Reasonably Based the Appropriate Determination in Part on the Availability of Controls for HAP Emissions From EGUs

In addition to determining that it was appropriate to regulate because of the known and potential hazards to public health and the environment, EPA also concluded that it was appropriate to regulate HAP emissions from EGUs because EPA had identified a number of control options that would effectively reduce HAP emissions from EGUs. 65 FR 79828-30. EPA discussed the various controls available to reduce HAP emissions from EGUs in the

December 2000 Finding. The approach of section 112, as amended in 1990, is based on the premise that, to the extent there are controls available to reduce HAP emissions, sources should be required to use them. Thus, it was reasonable to base the appropriate finding in part on the conclusion that controls currently available were expected to reduce HAP emissions from EGUs.

4. EPA Reasonably Concluded It Was Necessary To Regulate EGUs

In 2000, EPA found it was necessary to regulate HAP emissions from EGUs under section 112 because the imposition of the other requirements of the CAA would not address the serious public health and environmental hazards arising from such emissions. 65 FR 79830. EPA also noted that Congress enacted section 112 specifically to address HAP emissions from stationary sources, and it was thus reasonable to regulate HAP emissions from EGUs under that section given the hazards to public health and the environment posed by such emissions. *Id.*

In Table 1 of the December 20, 2000 notice, EPA set forth its projections of HAP emissions for 2010. In assessing those projections in 2000, EPA considered the data that it had obtained as the result of the 1999 ICR. 65 FR 79828. It also considered projected changes in the population of units, fuel consumption, and control device configuration. *Id.* EPA considered control device configurations in making the 2010 projections, in an effort to account for the reductions attributable to the imposition of other requirements of the CAA.

Specifically, in estimating the projected 2010 HAP emissions from EGUs, EPA accounted for the HAP

reductions that would occur as the result of the controls required to comply with the ARP. Congress added the ARP in CAA Title IV, as part of the 1990 amendments, and that program is primarily directed at EGUs. EPA, therefore, considered the HAP reductions projected to occur as the result of control configurations needed to meet the Acid Rain requirements of the CAA. *See, e.g.*, Utility Study, ES-2.

As shown in Table 1 of the December 20, 2000 notice, EPA estimated that the level of all HAP emitted by coal-fired EGUs would increase by 2010. 65 FR 79828 (Table 1). For Hg, EPA estimated that EGUs emitted 46 tons of Hg in 1990 and 43 tons of Hg in 1999, and it projected that EGUs would emit approximately 60 tons of Hg in 2010. 65 FR 79827-828. EPA also estimated an overall increase in non-Hg HAP emissions from coal-fired EGUs. Given these estimates and projections, which were based on the best information available at the time, EPA reasonably concluded that the identified and potential hazards associated with HAP from coal-fired EGUs would not be addressed through imposition of the other requirements of the CAA.

For oil-fired EGUs, EPA projected a decline in overall HAP emissions. The decline was primarily due to projected retirements and fuel switching from oil to natural gas. EPA could not conclude based on the information available at the time that the facilities posing the cancer risks, due primarily to Ni emissions, would retire or change fuels. As a result of these uncertainties and the uncertainties as to the extent of the public health impact from oil-fired units, EPA found that it was necessary to regulate such units under section 112.

5. The 2005 Action: EPA Erred in the 2005 Action by Concluding That the December 2000 Finding Lacked Foundation

In 2005, the Agency asserted that the December 2000 Finding lacked foundation for two reasons. First, the Agency stated that the 2000 appropriate finding was overbroad to the extent it relied on adverse environmental effects. Second, the Agency stated that the 2000 appropriate finding lacked foundation because EPA did not fully consider the Hg emissions remaining after imposition of the requirements of the CAA. For the reasons provided below, we reject these assertions as unfounded. As demonstrated above, EPA's 2000 appropriate and necessary finding was sound and fully supported by the record before the Agency in 2000.

a. Consideration of Environmental Effects in the Appropriate Finding

EPA reasonably examined the adverse environmental impacts associated with Hg in making the December 2000 Finding. In 2005, EPA changed its interpretation of the broad term "appropriate" to restrict the consideration of environmental effects only to situations where the Agency had determined that a hazard to public health exists as a result of EGU HAP emissions. As such, EPA stated in 2005 that the December 2000 Finding lacked foundation to the extent it was based on environmental effects.

As explained above in Section III.A, EPA's 2005 change in how it interpreted the term "appropriate" lacks merit. Congress gave EPA broad discretion to determine whether it was appropriate to regulate EGUs under section 112. On the one hand, EPA recognized that broad discretion in 2005, but on the

other hand, it sought to limit that discretion by only allowing environmental impacts to be considered if a hazard to public health was found. The 2005 interpretation was based on the flawed notion that the Agency should only consider health effects because the Utility Study only required consideration of hazards to public health. But, as noted above, Congress specifically directed EPA in section 112(n)(1)(B) to consider the environmental effects associated with Hg emissions from EGUs. It was entirely reasonable, therefore, for EPA to consider such effects in making its appropriate finding in 2000.

Furthermore, even under the Agency's flawed 2005 interpretation, which allowed consideration of environmental effects only where a hazard to public health exists, EPA properly considered environmental effects in 2000 because we, in fact, found a hazard to public health based on the record at that time.

b. Scope of "Appropriate" Finding

EPA interprets the "appropriate" finding to require an evaluation of the hazards to public health and the environment at the time of the finding. This interpretation is consistent with the approach taken in 2000. By contrast, in the 2005 "appropriate" analysis, EPA considered the hazards to public health that were reasonably anticipated to occur "after imposition of the requirements of the Act." In short, EPA infused the "after imposition of the requirements of the Act" inquiry into both the appropriate and necessary prongs.

As explained in Section III.A, this interpretation improperly conflates the "appropriate" and "necessary" analysis. Accordingly, any assertion that EPA's 2000 appropriate finding is flawed because the

Agency failed to consider the other requirements of the CAA should be rejected.

Even considering the Agency's flawed 2005 interpretation of the term "appropriate," there is nothing in the record to suggest that the Agency erred in 2000 with regard to assessing Hg emissions. As explained above, in 2000, EPA reasonably considered those requirements of the CAA that directly pertained to EGUs (*i.e.*, the ARP in Title IV of the Act).

In addition, in 2000, EPA recognized that EGUs may be subject to requirements pursuant to SIP developed in response to NAAQS. In fact, EPA had projected a potential 11 tpy reduction in EGU Hg emissions as the result of the ozone and PM NAAQS. Utility Study, p. 1-3. EPA explained in the Utility Study, however, why it did not account for such reductions in its 2010 emission projections.

First, EPA explained that some of the Hg reductions associated with the PM and ozone NAAQS would be realized through the implementation of the ARP, and, thus, had already been accounted for in its 2010 projections. *See* Utility Study, page 1-3. Thus, to consider the projected reductions from the NAAQS would have potentially led to double counting of the estimated HAP reductions. Second, the states, not EPA, are primarily responsible for implementation of the NAAQS. EPA could not have reasonably assumed that the estimated Hg reductions from EGUs would occur because it could not forecast the prospective regulatory actions of the states and the impact that those actions would have on HAP emissions. In short, there was no guarantee that states would regulate EGUs to achieve the reductions necessary to meet the NAAQS in such a way that would achieve Hg

reductions, and EPA reasonably did not consider such possible reductions in its 2000 analysis.

Furthermore, at the time of the Utility Study, no areas had been designated as nonattainment with the 1997 revised PM NAAQS. *See* Utility Study, page 2-32. Even had all areas been designated at the time of the Utility Study, we still would not have known how the states would have elected to obtain the required reductions to meet the NAAQS. We also would not have had information as to how the sources would actually implement the requirements in any SIP, and as noted above, the degree of HAP co-benefit reductions varies depending on the control approach used. Even had we considered the potential 11 tpy of Hg reductions estimated to occur as a result of implementing the 1997 NAAQS, the projected level of Hg emissions from EGUs in 2010 would have been 49 tpy (60 - 11 = 49), which is still 6 tpy greater than the 43 tpy that the Agency concluded in 2000 caused a hazard to public health and the environment. Thus, even if the NAAQS had been included in the 2010 projections, the Agency would still have found that the identified hazards would not be resolved through imposition of the requirements of the CAA and would have concluded it was necessary to regulate EGUs under section 112.

EPA also asserted in 2005 that it failed to account for Hg reductions associated with the 1997 Utility NSPS in assessing whether it was appropriate to regulate in 2000. In the Utility Study, EPA noted that EGUs would be implementing the same controls for NO[X] and SO[2] to meet the requirements of both Title I and Title IV. EPA accounted for the ARP in its 2010 projections. In addition, in the Utility Study, EPA determined that HAP emissions from EGUs

would increase in 2010 based on estimated increases in coal use, which was primarily projected to occur at new units. Utility Study, pages 2-26 to 2-31. Because EPA was unable to determine the size and location of the new units at the time of the Utility Study, the Agency reasonably allocated the increased fuel consumption to existing units (excluding the coal-fired units that were projected to retire between 1990 and 2010). All or a substantial majority of existing units already had some type of PM control and many units had scrubbers. To the extent this approach of assigning increased fuel consumption to existing controlled units led to an overestimation of remaining HAP emissions, we do not believe the overestimation was significant. EPA's approach to projecting emissions in 2010 was entirely reasonable given the data and information available to the Agency at the time. See Utility Study, page 6-15.

Finally, EPA asserted in 2005 that it failed to account for the Hg reductions associated with the NO[X] SIP call. Like the NAAQS, states are primarily responsible for developing regulations to meet the NO[X] SIP call. EPA could not have reasonably assumed that the estimated Hg reductions from EGUs would occur because it could not forecast the prospective regulatory actions of the states. In addition, in 2005, EPA neither identified the reductions that would occur as the result of the NO[X] SIP call, nor explained how those reductions would have changed EPA's 2000 appropriate finding.

EPA solicits comment on section III.B.

C. EPA Must Regulate EGUs Under Section 112 Because EGUs Were Properly Listed Under CAA Section 112(c)(1) and may not be Delisted Because They do not Meet the Delisting Criteria in CAA Section 112(c)(9)

As shown above, in 2000, EPA reasonably determined, based on the record before it at the time, that it was appropriate and necessary to regulate EGUs under CAA section 112. Once that finding was made, EPA properly listed EGUs pursuant to section 112(c), and EGUs remain a listed source category. *See New Jersey*, 517 F.3d at 583.

As the DC Circuit Court held in *New Jersey*, EPA cannot ignore the delisting criteria in section 112(c)(9). CAA section 112(c)(9)(B) authorizes the Agency to delist any source category if the Agency determines that: (1) For HAP that may cause cancer in humans, no source in the category emits such HAP in quantities that "may cause a lifetime risk of cancer greater than one in one million" to the most exposed individual; section 112(c)(9)(B)(i); and (2) for HAP that may result human health effects other than cancer or adverse environmental effects, "emissions from no source in the category or subcategory concerned * * * exceeds a level which is adequate to protect public health with an ample margin of safety and no adverse environmental effect will result from emissions from any source." Section 112(c)(9)(B)(ii).

Here, we have a validly listed source category. EPA could not have met the delisting criteria in 2000 or 2005, and it still cannot meet those criteria today.

The information in the Utility Study shows that HAP emissions from a number of EGUs caused a lifetime cancer risk greater than one in one million.

Nothing in the 2005 record suggested anything to the contrary, and as such, the Agency did not delist EGUs in 2005 pursuant to section 112(c)(9). Finally, EPA has conducted 16 case studies based on the data collected in support of this proposed rule and determined that 4 of those facilities evaluated (25 percent) presented a lifetime cancer risk greater than 1 in 1 million. Thus, based on current data and analysis, EGUs fail the first requirement for delisting set forth in section 112(c)(9)(B)(i). Because EGUs do not meet the first delisting requirement, the Agency need not determine whether the second delisting requirement is satisfied; however, the Agency believes that EGUs would similarly fail the second delisting requirement for the reasons described below in section III.D.

D. New Analyses Confirm That it Remains Appropriate and Necessary to Regulate U.S. EGU HAP Under Section 112

As explained above, the December 2000 appropriate and necessary determination is wholly supported by the record that was before the Agency at the time it made its decision. Although not required, we conducted additional technical analyses because several years have passed since the December 2000 Finding. These extensive analyses confirm that it remains appropriate and necessary today to regulate EGUs under section 112. We discuss below the new analyses that we conducted. We also explain why these analyses and the other information currently before the Agency confirm that regulation of EGUs under section 112 is appropriate and necessary. We solicit comment on the new analyses.

Utilities are by far the largest remaining source of Hg in the U.S.[26] In addition, EGUs are the largest source of HCl, HF, and Se emissions, and a major source of metallic HAP emissions including As, Cr, Ni, and others.[27] The discrepancy is even greater now that almost all other major source categories have been required to control Hg and other HAP under section 112.

These significant HAP emissions pose a known or potential hazard to public health and the environment and, thus, it remains appropriate to regulate EGUs under section 112.

In this section, we describe briefly the health and environmental effects associated with the HAP emitted by EGUs and summarize the new analyses that the Agency conducted to assess the hazards to public health and the environment associated with EGU emissions, including the hazards remaining after imposition of the requirements of the CAA. We then discuss our conclusion that it remains appropriate and necessary to regulate EGUs under section 112.

Specifically, we conclude today that it remains appropriate to regulate EGUs under section 112 because Hg is a persistent, bioaccumulative pollutant, and emissions of Hg from EGUs continue to pose a hazard to public health and to the environment. Because of the persistent nature of Hg in the environment, Hg emitted today can lead to re-emissions of Hg in the future, and as a result continue

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[26] Strum, M., Houyoux, M., U.S. Environmental Protection Agency. Emissions Overview: Hazardous Air Pollutants in Support of the Proposed Toxics Rule. Memorandum to Docket EPA-HQ-OAR-2009-0234. March 15, 2011.

[27] Ibid. Tables 3 and 4.

to contribute to Hg deposition and associated health and environmental hazards in the future.

In addition, we conclude today that it is appropriate to regulate non-Hg HAP because emissions of these HAP from some EGUs pose a cancer risk greater than one in one million to the most exposed individual.[28] EGUs remain the largest contributors of several HAP (*e.g.*, HF, Se, HCl), and are among the largest contributor for other HAP (*e.g.*, As, Cr, Ni, hydrogen cyanide (HCN)).[29] EPA recognizes that there are additional health and environmental effects for which we have insufficient information to quantify risks, or which have a higher degree of uncertainty regarding the weight of evidence for causality. While not quantified in our analysis, the potential for additional hazards to public health and the environment beyond what we have analyzed provides additional support for regulation under section 112 that will assure reductions of all HAP and the risks, quantified or unquantified, that they pose.

Finally, we find that it remains appropriate to regulate EGUs under section 112 because we have identified a number of currently available control technologies that will adequately address HAP emissions from EGUs. Several of these findings provide an independent basis for our determination consistent with our interpretation of the appropriate finding set forth above, and the combined weight of

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[28] Strum, M., Thurman, J., and Morris, M., U.S. Environmental Protection Agency. Non-Hg Case Study Chronic Inhalation Risk Assessment for the Utility MACT "Appropriate and Necessary" Analysis. Memorandum to Docket EPA-HQ-OAR-2009-0234. March 1, 2011.

[29] Strum, M., Houyoux, H., op. cit., Tables 3 and 4.

these findings provides a strong overall basis for our determination that it is and remains appropriate to regulate EGUs under CAA section 112.

We conclude that it remains necessary to regulate HAP emissions from EGUs because the imposition of the requirements of the CAA will not sufficiently address the hazards to public health and the environment posed by Hg emissions or the cancer risk and potential hazards to the environment posed by non-Hg HAP emissions from EGUs. Although the identified hazards will not be fully addressed through regulation under section 112, there will be a significant reduction in domestic Hg and non-Hg HAP emissions as the result of a section 112 regulation. EGUs remain the largest source of HCl and HF emissions in the U.S., and it is essential that those emissions be reduced to the maximum extent achievable, as Congress envisioned pursuant to section 112. Furthermore, it is necessary to regulate EGUs under section 112 because standards under that section assure that reductions in HAP emissions from EGUs will be permanently realized, thereby assuring that recent decreases in HAP emissions from U.S. EGUs will not be reversed in the future. Each of these conclusions independently supports our determination that it remains necessary to regulate EGUs under section 112.

Below we present an overview of EPA's current view of the scientific and technical information relevant to evaluating U.S. EGU Hg emissions and the public health hazards associated with such emissions. We provide general background information on the health hazards and environmental impacts of Hg and its transformation product MeHg; the emissions of those pollutants; the U.S. EGU contribution to these

emissions; the predominant exposure pathway by which humans are affected by MeHg, which is by ingestion of fish containing MeHg; EPA's methodology for determining the impacts of U.S. EGU Hg emissions on potential exposures to MeHg in fish; the estimated potential risks associated with recent and future anticipated emissions of Hg from U.S. EGUs; and a qualitative analysis of the environmental hazards associated with Hg deposition. In addition to these analyses of hazards to public health and the environment associated with emissions of Hg from U.S. EGUs, this section also includes analyses of the hazards to public health and the environment from U.S. EGU emissions of non-Hg HAP. We then explain why the hazards to public health and the environment from Hg and non-Hg HAP emissions are reasonably anticipated to remain from U.S. EGUs after imposition of the requirements of the CAA. Finally, we discuss our evaluation of the new data and our finding that it remains appropriate and necessary to regulate EGUs under section 112.

1. Background Information on Hg Emissions, Deposition, and Effects on Human Health and the Environment

a. Overview of Hg and Associated Health and Environmental Hazards

Mercury is a persistent, bioaccumulative toxic metal that is emitted from EGUs in three forms: Gaseous elemental Hg (Hg<0>), oxidized Hg compounds (Hg<+2>), and particle-bound Hg (Hg[P]). Elemental Hg does not quickly deposit or chemically react in the atmosphere, resulting in residence times that are long enough to contribute to global scale deposition. Oxidized Hg and Hg[P] deposit quickly from the atmosphere impacting local and regional areas in

proximity to sources. Methylmercury is formed by microbial action in the top layers of sediment and soils, after Hg has precipitated from the air and deposited into waterbodies or land. Once formed, MeHg is taken up by aquatic organisms and bioaccumulates up the aquatic food web. Larger predatory fish may have MeHg concentrations many times, typically on the order of one million times, that of the concentrations in the freshwater body in which they live. Although Hg is toxic to humans when it is inhaled or ingested, we focus in this rulemaking on exposure to MeHg through ingestion of fish, as it is the primary route for human exposures in the U.S., and potential health risks do not likely result from Hg inhalation exposures associated with Hg emissions from utilities.

In 2000, the National Research Council (NRC) of the NAS issued the NAS Study, which provides a thorough review of the effects of MeHg on human health. There are numerous studies that have been published more recently that report effects on neurologic and other endpoints.

i. Reference and Benchmark Doses

As discussed earlier in Sections II.A.1 and III.B.3.a.i of this preamble, EPA has set and evaluated the RfD for Hg several times, and has received input from the NRC on the appropriateness of the RfD. In 1995, EPA set a health-based ingestion rate for chronic oral exposure to MeHg termed an oral RfD, at 0.0001 milligrams per kilogram per day (mg/kg-day).[30] The RfD was based on effects reported for children exposed

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[30] MeHg exposure is measured as milligrams of MeHg per kilogram of bodyweight per day, thus normalizing for the size of fish meals and the differences in bodyweight among exposed individuals.

in utero during the Iraqi Hg poisoning episode, in which children were exposed to high levels of Hg when their mothers consumed contaminated grain.[31] Subsequent research from large epidemiological studies in the Seychelles,[32] Faroe Islands,[33] and New Zealand[34] added substantially to the body of knowledge on neurological effects from MeHg exposure. In 2001 EPA established a revised RfD based on the advice of the NAS and an independent review panel convened as part of the Integrated Risk Information System (IRIS) process. In their analysis, the NAS examined in detail the epidemiological data from the Seychelles, the Faroe Islands, and New Zealand, as well as other toxicological data on MeHg. The NAS recommended that neurobehavioral deficits

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[31] Marsh DO, Clarkson TW, Cox C, Myers GJ, Amin-Zaki L, Al-Tikriti S 1987. Fetal methylmercury poisoning. Relationship between concentration in single strands of maternal hair and child effects. Arch Neurol 44(10):1017-1022.

[32] Davidson, P.W., G. Myers, C.C. Cox, C.F. Shamlaye, D.O.Marsh, M.A.Tanner, M. Berlin, J. Sloane-Reeves, E. Chernichiari,, O. Choisy, A. Choi and T.W. Clarkson. 1995. Longitudinal neurodevelopment study of Seychellois children following in utero exposure to methylemrcury from maternal fish ingestion: outcomes at 19 and 29 months. NeuroToxicology 16:677-688.

[33] Grandjean, P., Weihe, P., White, R.F., Debes, F., Araki, S., Murata, K., Sorensen, N., Dahl, D., Yokoyama, K., Jorgensen, P.J., 1997. Cognitive deficit in 7-year-old children with prenatal exposure to methylmercury. Neurotoxicol. Teratol. 19, 417-428.

[34] Kjellstrom T, Kennedy P, Wallis S, Stewart A, Friberg L, Lind B, et al. (1989). Physical and mental development of children with prenatal exposure to mercury from fish. Stage 2: Interviews and psychological tests at age 6. Solna, Sweden: National Swedish Environmental Protection Board. Report No.: Report 3642.

as measured in several different tests among these studies be used as the basis for the RfD.

The NAS proposed that the Faroe Islands cohort was the most appropriate study for defining an RfD, and specifically selected children's performance on the Boston Naming Test (a neurobehavioral test) as the key endpoint. Results from all three studies were considered in defining the RfD, as published in the "2001 Water Quality for the Protection of Human Health: Methylmercury," and in the IRIS summary for MeHg: "Rather than choose a single measure for the RfD critical endpoint, EPA based this RfD for this assessment on several scores from the Faroes' measures, with supporting analyses from the New Zealand study, and the integrative analysis of all three studies."[35]

EPA defined the updated RfD of 0.0001 mg/kg-day in 2001. Although derived from a more complete data set and with a somewhat different methodology, the current RfD is numerically the same as the previous (1995) RfD (0.0001 mg/kg-day, or 0.1 [mu]g/kg-day).

This RfD, consistent with the standard definition, is an estimate (with uncertainty spanning perhaps an order of magnitude) of a daily exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime (EPA, 2002). In general EPA believes that exposures at or below the RfD are unlikely to be associated with appreciable risk of deleterious effects. However, no RfD defines an exposure level corresponding to zero risk; moreover the RfD does not represent a bright line, above which individuals are at risk of adverse effects. EPA's

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[35] EPA, 2001.

interpretation for this assessment is that any exposures to MeHg above the RfD are of concern given the nature of the data available for Hg that is not necessarily available for many other chemicals. The scientific basis for the Hg RfD includes extensive human data and extensive data on sensitive subpopulations, including pregnant mothers; therefore, the RfD does not include extrapolations from animals to humans, and from the general population to sensitive subpopulations. In addition, there was no evidence of a threshold for MeHg-related neurotoxicity within the range of exposures in the Faroe Islands study which served as the primary basis for the RfD. This additional confidence in the basis for the RfD suggests that all exposures above the RfD can be interpreted with more confidence as causing a potential hazard to public health. Studies published since the current MeHg RfD was released include new analyses of children's neuropsychological effects from the existing Seychelles and Faroe Islands cohorts, including formation of a new cohort in the Faroe Islands study. There are also a number of new studies that were conducted in population-based cohorts in the U.S and other countries. A comprehensive assessment of the new literature has not been completed by EPA. However, data published since 2001 are generally consistent with those of the earlier studies that were the basis of the RfD, demonstrating persistent effects in the Faroe Island cohort, and in some cases associations of effects with lower MeHg exposure concentrations than in the Faroes. These new studies provide additional confidence that exposures above the RfD are contributing to risk of adverse effects, and that reductions in exposures above the RfD can lead to incremental reductions in risk.

ii. Neurologic Effects

In its review of the literature, the NAS found neurodevelopmental effects to be the most sensitive and best documented endpoints and appropriate for establishing an RfD;[36] in particular NAS supported the use of results from neurobehavioral or neuropsychological tests. The NAS report[37] noted that studies in animals reported sensory effects as well as effects on brain development and memory functions and support the conclusions based on epidemiology studies. The NAS noted that their recommended endpoints for an RfD are associated with the ability of children to learn and to succeed in school. They concluded the following: "The population at highest risk is the children of women who consumed large amounts of fish and seafood during pregnancy. The committee concludes that the risk to that population is likely to be sufficient to result in an increase in the number of children who have to struggle to keep up in school."

iii. Cardiovascular Impacts

The NAS summarized data on cardiovascular effects available up to 2000 (IRIS 2001). Based on these and other studies, the NRC (2000) concluded that "Although the data base is not as extensive for cardiovascular effects as it is for other end points (*i.e.*, neurologic effects) the cardiovascular system appears to be a target for MeHg toxicity in humans and animals." The NRC also stated that "additional studies are needed to better characterize the effect of

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[36] NAS, 2000.

[37] NAS, 2000.

methylmercury exposure on blood pressure and cardiovascular function at various stages of life."

Additional cardiovascular studies have been published since 2000. EPA did not to develop a quantitative dose-response assessment for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects. In addition, there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. The pharmacokinetics of some of the exposure measures (such as toenail Hg levels) are not well understood. The studies have not yet received the review and scrutiny of the more well-established neurotoxicity data base.

iv. Genotoxic Effects

The Mercury Study noted that MeHg is not a potent mutagen but is capable of causing chromosomal damage in a number of experimental systems. The NAS concluded that evidence that human exposure to MeHg caused genetic damage is inconclusive; they note that some earlier studies showing chromosomal damage in lymphocytes may not have controlled sufficiently for potential confounders. One study of adults living in the Tapajos River region in Brazil[38] reported a direct relationship between MeHg concentration in hair and DNA damage in lymphocytes; as well as effects on chromosomes. Long-

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[38] Amorim, M.I., Mergler, D., Bahia, M.O., Dubeau, H., Miranda, D., Lebel, J., Burbano, R.R., Lucotte, M., 2000. Cytogenetic damage related to low levels of methyl mercury contamination in the Brazilian Amazon. An. Acad. Bras. Cienc. 72, 487-507.

term MeHg exposures in this population were believed to occur through consumption of fish, suggesting that genotoxic effects (largely chromosomal aberrations) may result from dietary, chronic MeHg exposures similar to and above those seen in the Faroes and Seychelles populations.

v. Immunotoxic Effects

Although exposure to some forms of Hg can result in a decrease in immune activity or an autoimmune response,[39] evidence for immunotoxic effects of MeHg is limited.[40]

vi. Other Human Toxicity Data

Based on limited human and animal data, MeHg is classified as a "possible" human carcinogen by the International Agency for Research on Cancer (IARC)[41] and in IRIS.[42] The existing evidence supporting the possibility of carcinogenic effects in humans from low-dose chronic exposures is tenuous. Multiple human epidemiological studies have found no significant association between Hg exposure and overall cancer incidence, although a few studies have shown an association between Hg exposure and specific types of

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[39] Agency for Toxic Substances and Disease Registry (ATSDR). 1999. Toxicological profile for Mercury. Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. http://www.atsdr.cdc.gov/toxprofiles/tp.asp?id=115&tid=24.

[40] National Academy of Sciences. Toxicologic effects of methylmercury. Washington, DC: National Research Council, 2000. Available online at http://www.nap.edu/openbook.php?isbn=0309071402.

[41] IARC, 1994.

[42] EPA, 2002.

cancer incidence (*e.g.*, acute leukemia and liver cancer.[43]

There is also some evidence of reproductive and renal toxicity in humans from MeHg exposure. However, overall, human data regarding reproductive, renal, and hematological toxicity from MeHg are very limited and are based on either studies of the two high-dose poisoning episodes in Iraq and Japan or animal data, rather than epidemiological studies of chronic exposures at the levels of interest in this analysis.

b. Mercury Emissions

Mercury is an element. There is a fixed amount of it in the world. As long as it is bound up, for example in coal, it cannot affect people or the environment. Once it is released, for example via the combustion process, it enters the environment and becomes available for chemical conversion. Once emitted, Hg remains in the environment, and can bioaccumulate in organisms or be remitted through natural processes. Mercury is emitted through natural and anthropogenic processes; in addition, previously deposited Hg from either process may be re-emitted. Mercury deposition in the U.S. is not directly proportional to total Hg emissions, due to the differing rates at which the three species of Hg (Hg<0>, Hg<+2>, Hg[p]) deposit. In general, the greater the fraction of total Hg accounted for by Hg<+2> and Hg[P], the higher the correlation between total Hg emissions and total Hg deposition in the U.S. In the following discussion, we will be describing emissions of Hg, while we discuss deposition later in this section.

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[43] NAS, 2000.

The categories for anthropogenic Hg emissions include the combustion of fossil-fuels, cement production, waste incineration, metals production, and other industrial processes. Anthropogenic Hg emissions consist of Hg<0>, Hg<+2>, and Hg[P].

Mercury re-emissions include previously deposited Hg originating from both natural and anthropogenic sources. At this time, it is not possible to determine the original source of previously deposited Hg, whether its source is natural emissions or re-emissions from previously deposited anthropogenic Hg.[44] [45] [46] It is believed that half of re-emitted Hg originates from anthropogenic sources.[47] [48]

Current estimates of total global Hg emissions based on a 2005 inventory range from 7,300 to 8,300

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[44] Lindberg, S., Bullock, R., Ebinghaus, R., Engstrom, D., Feng, X., Fitzgerald, W., et al. (2007). A Synthesis of Progress and Uncertainties in Attributing the Sources of Mercury in Deposition. Ambio, 36 (1), 19-33.

[45] Lohman, K., Seigneur, C., Gustin, M., & Lindberg, S. (2008). Sensitivity of the global atmospheric cycle of mercury to emissions. Applied Geochemistry, 23(3), 454-466.

[46] Seigneur, C., Vijayaraghavan, K., Lohman, K., Karamchandani, P., & Scott, C. (2004). Global Source Attribution for Mercury Speciation in the United States. Environmental Science and Technology (38), 555-569.

[47] Mason, R., Pirrone, N., & Mason, R. P. (2009). Mercury emissions from natural processes and their importance in the global mercury cycle. In Mercury Fate and Transport in the Global Atmosphere (pp. 173-191): Springer U.S.

[48] Selin, N. E., Jacob, D. J., Park, R. J., Yantosca, R. M., Strode, S., Jaegle, L., et al. (2007). Chemical cycling and deposition of atmospheric mercury: Global constraints from observations. J. Geophys. Res, 112, 1071-1077.

tpy.[49] [50] The United Nations Environment Programme (UNEP) estimates of 2005 global Hg emissions are somewhat lower, at 5,600 metric tpy.[51] Global anthropogenic Hg emissions, excluding biomass burning, have been estimated by many researchers. UNEP's 2005 estimate is approximately 2,100 tpy (with a range of 1,300 tpy to 3,300 tpy)[52] and Pirrone, *et al.*' s 2005 estimate is approximately 2,600 tpy. Global fossil-fuel fired EGUs total approximately 500 to 900 tpy, a large fraction (25 to 35 percent) of the total global anthropogenic emissions.[53] [54] The U.S.

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[49] Lindberg, S., Bullock, R., Ebinghaus, R., Engstrom, D., Feng, X., Fitzgerald, W., et al. (2007). A Synthesis of Progress and Uncertainties in Attributing the Sources of Mercury in Deposition. Ambio, 36 (1), 19-33.

[50] Pirrone, N., Cinnirella, S., Feng, X., Finkelman, R. B., Friedli, H. R., Leaner, J., et al. (2010). Global mercury emissions to the atmosphere from anthropogenic and natural sources. Atmospheric Chemistry and Physics Discussions, 10 (2), 4719-4752.

[51] UNEP (United Nations Environment Programme), Chemicals Branch, 2008. The Global Atmospheric Mercury Assessment: Sources, Emissions and Transport, UNEP Chemicals, Geneva.

[52] Study on Mercury Sources and Emissions and Analysis of the Cost and Effectiveness of Control Measures "UNEP Paragraph 29 study", UNEP (DTIE)/Hg/INC.2/4. November, 2010.

[53] Pirrone, N., Cinnirella, S., Feng, X., Finkelman, R. B., Friedli, H. R., Leaner, J., et al. (2010). Global mercury emissions to the atmosphere from anthropogenic and natural sources. Atmospheric Chemistry and Physics Discussions, 10 (2), 4719-4752.

[54] Study on Mercury Sources and Emissions and Analysis of the Cost and Effectiveness of Control Measures "UNEP Paragraph 29 study", UNEP (DTIE)/Hg/INC.2/4. November, 2010.

contribution to global anthropogenic emissions has declined from 10 percent in 1990 to 5 percent in 2005, due to reductions in U.S. emissions and increases in emissions from other countries.[55]

Although total U.S. anthropogenic Hg has decreased, the EGU sector remains the largest contributor to the total. In 1990, U.S. EGU Hg emissions for coal-fired units above 25 MW were 46 tons out of total U.S. Hg emissions of 264 tons.[56] By 1999 U.S. EGU Hg emissions for coal-fired units above 25 MW were 43 out of 115 tons.[57] In 2005, estimated emissions for coal- and oil-fired units above 25 MW were 53 tons out of a total of 105 tons. However, the 2005 estimate is based on control configurations as of 2002; therefore, it does not reflect reductions due to control installations that took place between 2002 and 2005. A current estimate of Hg emissions for both coal- and oil-fired units above 25 MW, using data from the EPA's 2010 ICR database, which used testing data for over 300 units, is 29 tons of Hg. We believe our estimate of the current level of Hg emissions based on the 2010 ICR database may underestimate total EGU Hg emissions due to the fact that emission factors used to develop the estimates may not accurately account for larger emissions from units with more poorly performing emission controls. EPA tested only 50 randomly selected units that were not selected for testing as best performing units (the bottom 85

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[55] The estimate of 5 percent is based upon 105 tons in 2005 divided by 2,100 tons from UNEP.

[56] The 46 ton estimate is based on the Utility Study. Since that time, EPA has updated its estimate of U.S. EGU Hg emissions in 1990. The updated estimate is 59 tons.

[57] Since the December 2000 Finding, the NEI process has led to an updated emissions estimate of 49 tons.

percent of units), and we used that small sample to attempt to characterize the lower performing units. Because the 50 units were randomly selected, we do not believe we have sufficiently characterized the units that have poorly performing controls. In addition, the 2010 estimate also reflects the installation of Hg controls to comply with state Hg-specific rules, voluntary reductions from EGUs, and the co-benefits of Hg reductions associated with control devices installed for the reduction of SO[2] and PM as a result of state and Federal actions, such as New Source Review (NSR) enforcement actions and implementation of CAIR. Table 3 shows U.S. EGU Hg emissions along with emissions from other major non-EGU Hg sources. Table 3 also shows EPA's projection that U.S. EGU emissions will continue to comprise a dominant portion of the total U.S. anthropogenic inventory in 2016. In 2016, U.S. EGU Hg emission for the subset of coal-fired units above 25 MW is projected to be 29 tons out of a total of 64 tons.[58]

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[58] As explained further in the emissions modeling TSD, this projection does not include reductions from a number of state-only Hg regulations and voluntary Hg reductions programs that are not Federally enforceable, and are not relevant to our assessment of whether it is appropriate and necessary to regulate U.S. EGU sources under section 112.

Table 3—Anthropogenic Hg Emissions and Projections in The U.S.*

Category	2005 Mercury (tons)	2016 Mercury (tons)
Electric Generating Units	53	29
Portland Cement Manufacturing	7.5	1.1
Stainless and Nonstainless Steel Manufacturing: Electric Arc Furnaces	7.0	4.6
Industrial, Commercial, Institutional Boilers & Process Heaters	6.4	4.6
Chemical Manufacturing	3.3	3.3
Hazardous Waste Incineration	3.2	2.1
Mercury Cell Chlor-Alkali Plants	3.1	0.3
Gold Mining	2.5	0.7
Municipal Waste Combustors	2.3	2.3
Sum of other source categories (each of which emits less than 2 tons)	17	16
Total	105	64

* Emissions estimates are presented at a maximum of two significant figures.

c. Atmospheric Processing and Deposition of Hg

Mercury is known to exist in the atmosphere in three forms: Hg<0>, Hg<+2>, and Hg[P]. The

dominant form of Hg in the atmosphere is Hg<0>.[59] Elemental Hg dominates total Hg composition in the atmosphere (greater than 95 percent) and has a much greater residence time than Hg<+2> or Hg[P]. Elemental Hg has a long atmospheric residence time due to its near insolubility in water and high vapor pressure which minimize removal through wet and dry deposition processes.[60] Oxidized Hg (which is soluble) and Hg[P] are more readily scavenged by precipitation and have higher dry deposition velocities than Hg<0> resulting in much shorter residence times. Although natural sources such as land, ocean and volcanic Hg are emitted as elemental, most anthropogenic sources are emitted in all three forms. EGU Hg ranges from 20 to 40 percent Hg<+2> and from 2 to 5 percent Hg[p]. This results in greater deposition of Hg<+2> and Hg[P] within the U.S. due to U.S. EGU emissions of these two Hg species, relative to emissions of Hg<0>. As a result, control of emissions of Hg<+2> and Hg[P] are more relevant for decreasing U.S. EGU-attributable exposures to MeHg for recreational and subsistence-level fish consumers than control of emissions of Hg<0>. Control of emissions of Hg<0> will still have value in reducing overall global levels of Hg deposition, and will, all else equal, eventually result in lower global fish MeHg

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[59] Schroeder, W. H. and J. Munthe (1998). "Atmospheric mercury—An overview." *Atmospheric Environment* 32(5): 809-822.

[60] Schroeder, W. H. and J. Munthe (1998). "Atmospheric mercury—An overview." *Atmospheric Environment* 32(5): 809-822.

Marsik, F. J., G. J. Keeler, et al. (2007). "The dry-deposition of speciated mercury to the Florida Everglades: Measurements and modeling." *Atmospheric Environment* 41(1): 136-149.

concentrations which can benefit both U.S. and global populations.

2. Background Information on Non-Hg HAP Emissions and Effects on Human Health and the Environment

a. Overview of Non-Hg HAP and Associated Health and Environmental Hazards

Emissions data collected through the 2010 ICR during development of this proposed rule show that HCl emissions represent the predominant HAP emitted by U.S. EGUs. Coal- and oil-fired EGUs emit lesser amounts of HF, chlorine (Cl[2]), metals 'As, Cd, Cr, Hg, Mn, Ni, and Pb), and organic HAP emissions. Although numerous organic HAP may be emitted from coal- and oil-fired EGUs, only a few account for essentially all the mass of organic HAP emissions. These organic HAP are formaldehyde, benzene, and acetaldehyde.

Exposure to high levels of the various non-Hg HAP emitted by EGUs is associated with a variety of adverse health effects. These adverse health effects include chronic (long-term) health disorders (*e.g.*, effects on the central nervous system, damage to the kidneys, and irritation of the lung, skin, and mucus membranes); and acute health disorders (*e.g.*, effects on the kidney and central nervous system, alimentary effects such as nausea and vomiting, and lung irritation and congestion). EPA has classified three of the HAP emitted by EGUs as human carcinogens and five as probable human carcinogens. The following sections briefly discuss the main health effects information we have regarding the key HAP emitted by EGUs in alphabetical order by HAP name.

i. Acetaldehyde

Acetaldehyde is classified in EPA's IRIS database as a probable human carcinogen, based on nasal tumors in rats, and is considered toxic by the inhalation, oral, and intravenous routes.[61] Acetaldehyde is reasonably anticipated to be a human carcinogen by the U.S. Department of Health and Human Services (DHHS) in the 11th Report on Carcinogens and is classified as possibly carcinogenic to humans (Group 2B) by the IARC.[62] [63] The primary noncancer effects of exposure to acetaldehyde vapors include irritation of the eyes, skin, and respiratory tract.[64]

ii. Arsenic

Arsenic, a naturally occurring element, is found throughout the environment and is considered toxic through the oral, inhalation and dermal routes. Acute (short-term) high-level inhalation exposure to As dust or fumes has resulted in gastrointestinal effects

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[61] U.S. Environmental Protection Agency (U.S. EPA). 1991. Integrated Risk Information System File of Acetaldehyde. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0290.htm.

[62] U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: http://ntp.niehs.nih.gov/go/16183.

[63] International Agency for Research on Cancer (IARC). 1999. Re-evaluation of some organic chemicals, hydrazine, and hydrogen peroxide. IARC Monographs on the Evaluation of Carcinogenic Risk of Chemical to Humans, Vol 71. Lyon, France.

[64] U.S. Environmental Protection Agency (U.S. EPA). 1991. Integrated Risk Information System File of Acetaldehyde. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0290.htm.

(nausea, diarrhea, abdominal pain, and gastrointestinal hemorrhage); central and peripheral nervous system disorders have occurred in workers acutely exposed to inorganic As. Chronic (long-term) inhalation exposure to inorganic As in humans is associated with irritation of the skin and mucous membranes. Chronic inhalation can also lead to conjunctivitis, irritation of the throat and respiratory tract and perforation of the nasal septum.[65] Chronic oral exposure has resulted in gastrointestinal effects, anemia, peripheral neuropathy, skin lesions, hyperpigmentation, and liver or kidney damage in humans. Inorganic As exposure in humans, by the inhalation route, has been shown to be strongly associated with lung cancer, while ingestion of inorganic As in humans has been linked to a form of skin cancer and also to bladder, liver, and lung cancer. EPA has classified inorganic As as a Group A, human carcinogen.[66]

iii. Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased

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[65] Agency for Toxic Substances and Disease Registry (ATSDR). Medical Management Guidelines for Arsenic. Atlanta, GA: U.S. Department of Health and Human Services. Available on the Internet at http://www.atsdr.cdc.gov/mhmi/mmg168.html#bookmark02.

[66] U.S. Environmental Protection Agency (U.S. EPA). 1998. Integrated Risk Information System File for Arsenic. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0278.htm.

proliferation of bone marrow cells in mice.[67] [68] [69] EPA states in its IRIS database that data indicate a causal relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The IARC has determined that benzene is a human carcinogen and the DHHS has characterized benzene as a known human carcinogen.[70] [71]

A number of adverse noncancer health effects including blood disorders, such as preleukemia and

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[67] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0276.htm.

[68] International Agency for Research on Cancer, IARC monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, International Agency for Research on Cancer, World Health Organization, Lyon, Francè, p. 345-389, 1982.

[69] Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. (1992) Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, Proc. Natl. Acad. Sci. 89:3691-3695.

[70] International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.

[71] U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: http://ntp.niehs.nih.gov/go/16183.

aplastic anemia, have also been associated with long-term exposure to benzene.[72] [73]

iv. Cadmium

Breathing air with lower levels of Cd over long periods of time (for years) results in a build-up of Cd in the kidney, and if sufficiently high, may result in kidney disease. Lung cancer has been found in some studies of workers exposed to Cd in the air and studies of rats that inhaled Cd. DHHS has determined that Cd and Cd compounds are known human carcinogens. IARC has determined that Cd is carcinogenic to humans. EPA has determined that Cd is a probable human carcinogen.[74]

v. Chlorine

The acute (short term) toxic effects of Cl[2] are primarily due to its corrosive properties. Chlorine is a strong oxidant that upon contact with water moist tissue (*e.g.*, eyes, skin, and upper respiratory tract) can produce major tissue damage.[75] Chronic inhalation exposure to low concentrations of Cl[2] (1 to 10 parts per million, ppm) may cause eye and nasal irritation,

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[72] Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. Environ. Health Perspect. 82: 193-197.

[73] Goldstein, B.D. (1988). Benzene toxicity. Occupational medicine. State of the Art Reviews. 3: 541-554.

[74] Agency for Toxic Substances and Disease Registry (ATSDR). 2008. Public Health Statement for Cadmium. CAS# 1306-19-0. Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. Available on the Internet at http://www.atsdr.cdc.gov/PHS/PHS.asp?id=46&tid=15.

[75] Agency for Toxic Substances and Disease Registry (ATSDR). Medical Management Guidelines for Chlorine. Atlanta, GA: U.S. Department of Health and Human Services. http://www.atsdr.cdc.gov/mmg/mmg.asp?id=198&tid=36.

sore throat, and coughing. Chronic exposure to Cl[2], usually in the workplace, has been reported to cause corrosion of the teeth. Inhalation of higher concentrations of Cl[2] gas (greater than 15 ppm) can rapidly lead to respiratory distress with airway constriction and accumulation of fluid in the lungs (pulmonary edema). Exposed individuals may have immediate onset of rapid breathing, blue discoloration of the skin, wheezing, rales or hemoptysis (coughing up blood or blood-stain sputum). Intoxication with high concentrations of Cl[2] may induce lung collapse. Exposure to Cl[2] can lead to reactive airways dysfunction syndrome (RADS), a chemical irritant-induced type of asthma. Dermal exposure to Cl[2] may cause irritation, burns, inflammation and blisters. EPA has not classified Cl[2] with respect to carcinogenicity.

vi. Chromium

Chromium may be emitted in two forms, trivalent Cr (Cr<+3>) or hexavalent Cr (Cr<+6>). The respiratory tract is the major target organ for Cr<+6> toxicity, for acute and chronic inhalation exposures. Shortness of breath, coughing, and wheezing have been reported from acute exposure to Cr<+6>, while perforations and ulcerations of the septum, bronchitis, decreased pulmonary function, pneumonia, and other respiratory effects have been noted from chronic exposures. Limited human studies suggest that Cr<+6> inhalation exposure may be associated with complications during pregnancy and childbirth, but there are no supporting data from animal studies reporting reproductive effects from inhalation exposure to Cr<+6>. Human and animal studies have clearly established the carcinogenic potential of Cr<+6> by the inhalation route, resulting in an

increased risk of lung cancer. EPA has classified Cr<+6> as a Group A, human carcinogen. Trivalent Cr is less toxic than Cr<+6>. The respiratory tract is also the major target organ for Cr<+3> toxicity, similar to Cr<+6>. EPA has not classified Cr<+3> with respect to carcinogenicity.

vii. Formaldehyde

Since 1987, EPA has classified formaldehyde as a probable human carcinogen based on evidence in humans and in rats, mice, hamsters, and monkeys.[76] EPA is currently reviewing recently published epidemiological data. After reviewing the currently available epidemiological evidence, the IARC (2006) characterized the human evidence for formaldehyde carcinogenicity as "sufficient," based upon the data on nasopharyngeal cancers; the epidemiologic evidence on leukemia was characterized as "strong."[77] EPA is reviewing the recent work cited above from the National Cancer Institute (NCI) and National Institute for Occupational Safety and Health (NIOSH), as well as the analysis by the CIIT Centers for Health Research and other studies, as part of a reassessment of the human hazard and dose-response associated with formaldehyde.

Formaldehyde exposure also causes a range of noncancer health effects, including irritation of the

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[76] U.S. EPA. 1987. Assessment of Health Risks to Garment Workers and Certain Home Residents from Exposure to Formaldehyde, Office of Pesticides and Toxic Substances, April 1987.

[77] International Agency for Research on Cancer (2006) Formaldehyde, 2-Butoxyethanol and 1-tert-Butoxypropan-2-ol. Monographs Volume 88. World Health Organization, Lyon, France.

eyes (burning and watering of the eyes), nose and throat. Effects from repeated exposure in humans include respiratory tract irritation, chronic bronchitis and nasal epithelial lesions such as metaplasia and loss of cilia. Animal studies suggest that formaldehyde may also cause airway inflammation—including eosinophil infiltration into the airways. There are several studies that suggest that formaldehyde may increase the risk of asthma—particularly in the young.[78] [79]

viii. Hydrogen Chloride

Hydrogen chloride is a corrosive gas that can cause irritation of the mucous membranes of the nose, throat, and respiratory tract. Brief exposure to 35 ppm causes throat irritation, and levels of 50 to 100 ppm are barely tolerable for 1 hour.[80] The greatest impact is on the upper respiratory tract; exposure to high concentrations can rapidly lead to swelling and spasm of the throat and suffocation. Most seriously exposed persons have immediate onset of rapid breathing, blue

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[78] Agency for Toxic Substances and Disease Registry (ATSDR). 1999. Toxicological profile for Formaldehyde. Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. http://www.atsdr.cdc.gov/toxprofiles/tp111.html

[79] WHO (2002) Concise International Chemical Assessment Document 40: Formaldehyde. Published under the joint sponsorship of the United Nations Environment Programme, the International Labour Organization, and the World Health Organization, and produced within the framework of the Inter-Organization Programme for the Sound Management of Chemicals. Geneva.

[80] Agency for Toxic Substances and Disease Registry (ATSDR). Medical Management Guidelines for Hydrogen Chloride. Atlanta, GA: U.S. Department of Health and Human Services. Available online at http://www.atsdr.cdc.gov/mmg/mmg.asp?id=758&tid=147#bookmark02.

coloring of the skin, and narrowing of the bronchioles. Exposure to HCl can lead to RADS, a chemically- or irritant-induced type of asthma. Children may be more vulnerable to corrosive agents than adults because of the relatively smaller diameter of their airways. Children may also be more vulnerable to gas exposure because of increased minute ventilation per kg and failure to evacuate an area promptly when exposed. Hydrogen chloride has not been classified for carcinogenic effects.[81]

ix. Hydrogen Fluoride

Acute (short-term) inhalation exposure to gaseous HF can cause severe respiratory damage in humans, including severe irritation and pulmonary edema. Chronic (long-term) oral exposure to fluoride at low levels has a beneficial effect of dental cavity prevention and may also be useful for the treatment of osteoporosis. Exposure to higher levels of fluoride may cause dental fluorosis. One study reported menstrual irregularities in women occupationally exposed to fluoride via inhalation. The EPA has not classified HF for carcinogenicity.[82]

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[81] U.S. Environmental Protection Agency (U.S. EPA). 1995. Integrated Risk Information System File of Hydrogen Chloride. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0396.htm.

[82] U.S. Environmental Protection Agency. Health Issue Assessment: Summary Review of Health Effects Associated with Hydrogen Fluoride and Related Compounds. EPA/600/8-89/002F. Environmental Criteria and Assessment Office, Office of Health and Environmental Assessment, Office of Research and Development, Cincinnati, OH. 1989.

x. Lead

The main target for Pb toxicity is the nervous system, both in adults and children. Long-term exposure of adults to Pb at work has resulted in decreased performance in some tests that measure functions of the nervous system. Lead exposure may also cause weakness in fingers, wrists, or ankles. Lead exposure also causes small increases in blood pressure, particularly in middle-aged and older people. Lead exposure may also cause anemia.

Children are more sensitive to the health effects of Pb than adults. No safe blood Pb level in children has been determined. At lower levels of exposure, Pb can affect a child's mental and physical growth. Fetuses exposed to Pb in the womb may be born prematurely and have lower weights at birth. Exposure in the womb, in infancy, or in early childhood also may slow mental development and cause lower intelligence later in childhood. There is evidence that these effects may persist beyond childhood.[83]

There are insufficient data from epidemiologic studies alone to conclude that Pb causes cancer (is carcinogenic) in humans. DHHS has determined that Pb and Pb compounds are reasonably anticipated to be human carcinogens based on limited evidence from studies in humans and sufficient evidence from animal studies, and EPA has determined that Pb is a probable human carcinogen.

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[83] Agency for Toxic Substances and Disease Registry (ATSDR). 2007. Public Health Statement for Lead. CAS#: 7439-92-1. Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. Available on the Internet at http://www.atsdr.cdc.gov/ToxProfiles/phs13.html.

xi. Manganese

Health effects in humans have been associated with both deficiencies and excess intakes of Mn. Chronic exposure to high levels of Mn by inhalation in humans results primarily in central nervous system effects. Visual reaction time, hand steadiness, and eye-hand coordination were affected in chronically-exposed workers. Manganism, characterized by feelings of weakness and lethargy, tremors, a masklike face, and psychological disturbances, may result from chronic exposure to higher levels. Impotence and loss of libido have been noted in male workers afflicted with manganism attributed to inhalation exposures. The EPA has classified Mn in Group D, not classifiable as to carcinogenicity in humans.[84]

xii. Nickel

Respiratory effects have been reported in humans from inhalation exposure to Ni. No information is available regarding the reproductive or developmental effects of Ni in humans, but animal studies have reported such effects. Human and animal studies have reported an increased risk of lung and nasal cancers from exposure to Ni refinery dusts and nickel subsulfide. The EPA has classified nickel subsulfide as a human carcinogen and nickel carbonyl as a probable

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[84] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Manganese. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1999.

human carcinogen.[85] [86] The IARC has classified Ni compounds as carcinogenic to humans.[87]

xiii. Selenium

Acute exposure to elemental Se, hydrogen selenide, and selenium dioxide (SeO[2]) by inhalation results primarily in respiratory effects, such as irritation of the mucous membranes, pulmonary edema, severe bronchitis, and bronchial pneumonia. One Se compound, selenium sulfide, is carcinogenic in animals exposed orally. EPA has classified elemental Se as a Group D, not classifiable as to human carcinogenicity, and selenium sulfide as a Group B2, probable human carcinogen.

b. Non-Hg HAP Emissions

Fossil-fuel fired boilers emit a variety of metal HAP, organic HAP and HAP that are acid gases. Acid gas and metal HAP emissions are discussed below.

i. Acid Gases

Based on the 2010 ICR and the National Air Toxics Assessment (NATA) inventory estimates of acid gas emissions, U.S. EGUs emit the majority of HCl and HF nationally, supporting EPA's view that it remains appropriate to regulate HAP from U.S. EGUs. Acid gas

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[85] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Nickel Subsulfide. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1999.

[86] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Nickel Carbonyl. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1999.

[87] Nickel (IARC Summary & Evaluation, Volume 49, 1990), http://www.inchem.org/documents/iarc/vol49/nickel.html.

emissions from EGUs include HCl, HF, Cl[2], and HCN. These pollutants are emitted as a result of fluorine, chlorine, and nitrogen components of the fuels. Table 4 of this preamble shows emissions of certain acid gases from EGUs, based on the 2005 NATA inventory. 2010 estimates of emissions for acid HAP from U.S. EGU are 7,900 tpy for HCN, 106,000 tons for HCl, and 36,000 tons for HF.[88]

Table 4—Summary of Acid Gas Emissions From EGU Sources

	2005 Acid HAP emissions from the National Air Toxics Assessment (NATA) (typ)		Percent of total U.S. anthropogenic emissions in 2005
	U.S. EGU emissons	U.S. Non-EGU emissions	Non-EGU emissions
Hydrogen Cyanide fn1	1,200	14,000	8
Hydrogen Chloride	350,000	78,000	82
Hydrogen Fluoride	47,000	28,000	62

fn1 Using cyanide emissions for HCN.

ii. Metal HAP

U.S. EGUs are the predominant source of emissions nationally for many metal HAP, including Sb, As, Cr, Co, and Se.

Metals are emitted primarily because they are present in fuels. Table 5 of this preamble shows

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[88] We believe our estimate of the current level of acid HAP emissions based on the 2010 ICR database may underestimate total EGU acid HAP emissions due to targeting of the 2010 ICR on the best performing EGUs.

selected metals emitted by EGUs and emission estimates based on data from the 2005 NATA inventory. 2010 estimates of metal HAP emissions are 25 tpy for antimony (Sb), 43 tpy for As, 2 tpy for Be, 3 tpy for Cd, 222 tpy for Cr, 19 tpy for Co, 183 tpy for Mn, 387 tpy for Ni, and 258 tpy for Se.[89] Depending on the metal, EGUs account for between 13 and 83 percent of national metal HAP emissions, and as a result it remains appropriate to regulate EGUs.

Table 5—Summary of Metal Emissions From EGU Sources

	2005 Metal HAP emissions from the inventory used for the National Air Toxics Assessment (NATA) (tpy)		Percent of total U.S. anthropogenic emissions in 2005
	U.S. EGU emissions	U.S. Non-EGU emissions	
Antimony	19	83	19
Arsenic	200	120	62
Beryllium	10	13	44
Cadmium	25	38	39
Chromium	120	430	22
Cobalt	54	60	47
Manganese	270	1,800	13
Nickel	320	840	28
Selenium	580	120	83

3. Quantitative Risk Characterizations To Inform the Appropriate and Necessary Finding

EPA conducted quantitative risk analyses to evaluate the extent of risk posed by emissions of HAP from U.S. EGUs. These analyses demonstrate that

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[89] We believe our estimate of the current level of metal HAP emissions based on the 2010 ICR database may underestimate total EGU metal HAP emissions due to targeting of the 2010 ICR on the best performing EGUs.

U.S. EGU HAP emissions do create the potential for risks to the public health, as described below.

a. Scope of Quantitative Risk Analyses

To evaluate the potential for public health hazards from emissions of Hg and non-Hg HAP from U.S. EGUs, EPA conducted quantitative risk analyses using several methods intended to address specific risk-related questions.[90] [91]<90 91> Outputs from this assessment include: (1) The potential exposures to MeHg and risks associated with current U.S. EGU Hg emissions for populations most likely to be at risk from exposure to MeHg associated with U.S. EGU Hg emissions; (2) excess deposition of Hg in nearby locations within 50 kilometers (km) of EGUs that might result in Hg deposition "hotspots"; (3) for populations living in the vicinity of EGUs, the maximum individual risks (MIR) associated with U.S. EGU non-Hg HAP emissions, for both cancer and non-cancer risks, compared to established health benchmarks (*e.g.*, greater than one in a million for cancer risks, and a HQ exceeding one for chronic non-cancer risks).[92]

To evaluate the potential for health risks associated with U.S. EGU Hg emissions, EPA conducted a

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[90] U.S. EPA. 2011. Technical Support Document: National-Scale Mercury Risk Assessment Supporting the Appropriate and Necessary Finding for Coal- and Oil-Fired Electric Generating Units. Office of Air Quality Planning and Standards.

[91] U.S. EPA. 2011. Technical Support Document: Non-Mercury HAP Case Studies Supporting the Appropriate and Necessary Finding for Coal- and Oil-Fired Electric Generating Units. Office of Air Quality Planning and Standards.

[92] The hazard quotient (HQ) is the estimated inhalation or ingestion exposure divided by the reference dose (RfD).

national scale assessment of the impacts of U.S. EGU Hg emissions on exposures to MeHg above the RfD, and as a contributor to exposures above the RfD in conjunction with exposures from other U.S. and non-U.S. Hg emissions. To evaluate risks of U.S. EGU Hg "hotspots," EPA conducted a national scale assessment based on the Hg deposition modeling used in the national-scale Hg risk assessment. To evaluate inhalation risks of U.S. EGU non-Hg HAP emissions, EPA recently conducted 16 case studies at EGUs. EPA selected these case studies based on HAP emissions information from the ICR. For each case study, EPA estimated the MIR for cancer and non-cancer health effects for each HAP emitted by the case study U.S. EGU facility. Cancer risks for non-Hg HAP are estimated as the number of excess cancer cases per million people. This section briefly describes the methods used in the analyses and the results for the national-scale Hg risk analysis and the non-Hg HAP inhalation risk case studies.

b. Emissions for Hg and Non-Hg HAP

The national-scale Hg risk analysis is based on modeling Hg deposition associated with 2005 U.S. EGU Hg emissions and 2016 projected Hg emissions.

The 2005 base case includes 105 tons of Hg and 430,000 tons of HCl from all sources, of which 53 tons of Hg and 350,000 tons of HCl are from EGUs. The 2016 projected total Hg emissions from all sources used in the risk modeling are 64 tons and HCl emissions are 140,000 tons, with 29 tons of Hg and 74,000 tons of HCl from EGUs. U.S. EGU Hg emissions accounted for 50 percent of total U.S. Hg emissions in 2005 and are projected to account for 45 percent of such emissions in 2016. Details regarding the emissions used in these analyses are provided in

the emissions memorandum, "Emissions Overview: Hazardous Air Pollutants in Support of the Proposed Toxics Rule".[93]

Between 2005 and 2010, Hg emissions in the U.S. have declined as a result of state regulations of Hg or Federal regulatory and enforcement actions that required installation of SO[2] scrubbers at EGUs which decreased Hg emissions.[94] The 2010 ICR shows the EGU Hg and HCl totals are lower than in 2005, at 29 tons and 106,000 tons respectively.

Given that the 2010 emissions for Hg are much closer to the 2016 projected emissions than to the 2005 emissions, we focus on the results from 2016 from the national-scale Hg risk analysis described below, as the projected emissions are almost the same as current HAP emissions from EGUs.

c. National-Scale Hg Risk Modeling

i. Purpose and Scope of Analysis

The national-scale risk assessment for Hg focuses on risk associated with Hg released from U.S. EGUs that deposits to watersheds within the continental U.S., bioaccumulates in fish, and then is consumed as MeHg in fish eaten by subsistence fishers and other freshwater self-caught fish consumers. The risk assessment is intended to assess risk for scenarios representing high-end self-caught fish consumers active at inland freshwater lakes and streams. This

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[93] Strum, M., Houyoux, M., op. cit., Section 4.

[94] The 2005 estimate is based on control configurations as of 2002, therefore it does not reflect reductions due to substantial control installations that took place between 2002 and 2005. The 2010 estimates reflect control information reported to EPA as part of the recent 2010 ICR in late 2009.

reflects our goal of determining whether U.S. EGUs represent a potential public health hazard for the group of fish consumers likely to experience the highest risk attributable to U.S. EGUs. In defining the high fish consuming populations included in the analysis, we have used information from studies of fish consumption to ensure that we have identified fisher populations that are likely active to some extent across the watersheds included in this analysis (*i.e.*, they are not purely hypothetical). The risk assessment considered the magnitude and prevalence of the risk to public health posed by current U.S. EGU Hg emissions and the remaining risk posed by U.S. EGU Hg emissions after imposition of the requirements of the CAA, as described more fully below. In both cases, we assess the contribution of U.S. EGUs to potential risks from MeHg exposure relative to total MeHg risk associated with Hg deposited by other sources both domestic and international.

Risk from Hg exposures occurs primarily through the consumption of fish that have bioaccumulated MeHg originally deposited to watersheds following atmospheric release and transport. The population that is most at risk from consumption of MeHg in fish is children born to mothers who were exposed to MeHg during pregnancy through fish consumption. The type of fish consumption likely to lead to the greatest exposure to MeHg attributable to U.S. EGUs is associated with fishing activity at inland freshwater rivers and lakes located in regions with elevated U.S. EGU Hg deposition. Thus we focus on MeHg exposure to women of childbearing age who consume self-caught freshwater fish on a regular basis, *e.g.*, once a day to once every several days.

As noted above, current U.S. EGU Hg emissions as reflected in the 2010 ICR are closer to 2016 projected emissions than to the 2005 emissions. For this reason, in discussing risk estimates, we focus on the 2016 results rather than the 2005 results.

The risk assessment compares the U.S. EGU incremental contribution to total potential exposure with the RfD and also evaluates the percent of total Hg exposures from all sources contributed by U.S. EGUs (*i.e.*, the fraction of total risk associated with U.S. EGUs) to individual watersheds for which we have fish tissue MeHg data.

We used this information to assess whether a public health hazard is associated with U.S. EGU emissions. Our focus is on women of child-bearing age in subsistence fishing populations who consume freshwater fish that they or their family caught. These populations are likely to experience the greatest risk from Hg exposure when fishing at inland (freshwater) locations that receive the highest levels of U.S. EGU-attributable Hg deposition. We also acknowledge that additional populations are likely exposed to MeHg from consuming fish caught in near-coastal, *e.g.*, estuarine environments. However, there is high uncertainty about the relationship of MeHg levels in those fish and deposition of Hg from U.S. EGUs, and as such we have not included those types of fish consumption in our analysis. However, it is likely that the range of potential exposures to U.S. EGU Hg deposition across inland watersheds captures the types of potential exposures that occur in near-coastal environments, and, thus, likely represents potential risks from consumption of fish caught in those environments.

Consumption rates for the high-end fishing populations included in the risk assessment are based on studies in the published literature, and are documented in the TSD accompanying this finding.

We do not estimate risks associated with commercial fish consumption because of the expected low contribution of U.S. EGU Hg to this type of fish, relative to non-U.S. Hg emissions, and the high levels of uncertainty in mapping U.S. EGU Hg emissions to concentrations of MeHg in ocean-going fish. The population affected by those U.S. EGU Hg emissions that go into the global pool of Hg will potentially be much larger than the population of the U.S. Thus, the impacts of U.S. EGUs on global exposures to Hg, while highly uncertain, adds additional support to the finding that Hg emissions from U.S. EGUs pose a hazard to public health.

ii. Risk Characterization Framework

EPA assessed risk from potential exposure to MeHg through fish consumption at a subset of watersheds across the country for which we have measured fish tissue MeHg data. This risk assessment uses estimates of potential exposure for subsistence fisher populations to generate risk metrics based on comparisons of MeHg exposure to the reference dose. We are focusing on exposures above the RfD because it represents a sensitive risk metric that captures a wide range of neurobehavioral health effects. Reductions in exposure to MeHg are also expected to result in reductions in specific adverse effects including lost IQ points, and we discuss the risk analysis related to IQ loss in the National Scale Mercury Risk Assessment TSD.

For the analysis, we have developed a risk characterization framework for integrating two types of U.S. EGU-attributable risk estimates. This framework estimates the percent of watersheds where populations may be at risk due to potential exposures to MeHg attributable to U.S. EGU. The analysis is limited to those watersheds for which we have fish tissue MeHg samples, a total of approximately 2,400 out of 88,000 watersheds in the U.S. This total percent of watersheds includes ones that either have deposition of Hg from U.S. EGUs that is sufficient to lead to potential exposures that exceed the reference dose, even without considering the contributions from other U.S. and non-U.S. sources, or have deposition of Hg from U.S. EGUs that contributes at least 5 percent to total Hg deposition from all sources, in watersheds where potential exposures to MeHg from all sources (U.S. EGU, U.S. non-EGU, and non-U.S.) exceed the RfD.

This framework allows EPA to consider whether U.S. EGUs, evaluated without consideration of other sources, or in combination with other sources of Hg, pose a potential public health hazard.

iii. Analytical Approach

Several elements of this risk analysis including spatial scale, estimates of Hg deposition, estimates of fish tissue MeHg concentrations, estimates of fish consumptions rates, and calculation of MeHg exposure are discussed in detail in the National Scale Mercury Risk Assessment TSD accompanying this finding, and are briefly summarized below.

Watersheds can be defined at varying levels of spatial resolution. For the purposes of this risk analysis, we have selected to use watersheds classified

using 12-digit Hydrologic Unit Codes (HUC12),[95] representing a fairly refined level of spatial resolution with watersheds generally 5 to 10 km on a side, which is consistent with research on the relationship between changes in Hg deposition and changes in MeHg levels in aquatic biota.

After estimating total MeHg risk based on modeling consumption of fish at each of these watersheds, the ratio of U.S. EGU to total Hg deposition over each watershed (estimated using Community Multi-scale Air Quality modeling) is used to estimate the U.S. EGU-attributable fraction of total MeHg risk. This apportionment of total risk between the U.S. EGU fraction and the fraction associated with all other sources of Hg deposition is based on the EPA's Office of Water's Mercury Maps (MMaps) approach that establishes a proportional relationship between Hg deposition over a watershed and resulting fish tissue Hg levels, assuming a number of criteria are met.[96]

The fish tissue dataset for the risk assessment includes fish tissue Hg samples from the years 2000 to 2009, with samples distributed across 2,461 HUC12s. The samples are more heavily focused on locations east of the Mississippi River. The fish tissue samples come primarily from three sources: the National Listing of Fish Advisory (NLFA) database managed by

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[95] U.S. Geological Survey and U.S. Department of Agriculture, Natural Resources Conservation Service, 2009, Federal guidelines, requirements, and procedures for the national Watershed Boundary Dataset: U.S. Geological Survey Techniques and Methods 11-A3, 55 p.

[96] Mercury Maps—A Quantitative Spatial Link Between Air Deposition and Fish Tissue Peer Reviewed Final Report. U.S. EPA, Office of Water, EPA-823-R-01-009, September, 2001.

EPA;[97] the U.S. Geologic Survey (USGS), which manages a compilation of Hg datasets as part of its Environmental Mercury Mapping and Analysis (EMMA) program, and EPA's National River and Stream Assessment (NRSA) study data. Most of the watersheds with measured fish tissue MeHg data had multiple measurements. This assessment used the 75th percentile fish tissue value at each watershed as the basis for exposure and risk characterization, based on the assumption that subsistence fishers would favor larger fish which have the potential for higher bioaccumulation. The use of the 75th percentile fish tissue MeHg value as the basis for risk characterization reflects our overall goal of modeling realistic high-end fishing behavior; in this case, reflecting individuals who target somewhat larger fish for purposes of supplementing their diets (the average fisher may eat a variety of different sized fish, but in order to capture higher potential MeHg exposure scenarios, it is realistic to assume that some fishers may favor somewhat larger fish).

Deposition of Hg for the continental U.S. was estimated using the Community Multiscale Air Quality model v4.7.1 (http://www.cmaq-model.org), applied at a 12 km grid resolution.

The CMAQ modeling was used to estimate total annual Hg deposition from U.S. and non-U.S. anthropogenic and natural sources over each watershed. In addition, CMAQ simulations were conducted where U.S. EGU Hg emissions were set to zero to determine the contribution of U.S. EGU Hg emissions to total Hg deposition. U.S. EGU-related Hg

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[97] http://water.epa.gov/scitech/swguidance/fishshellfish/fishadvisories/.

deposition characterized at the watershed-level for 2005 and 2016 is summarized in Table 6 of this preamble for the complete set of 88,000 HUC12 watersheds.

Table 6 is intended to demonstrate the wide variation across watersheds in the contribution of EGU emissions to deposition. The percentiles of total Hg deposition and U.S. EGU-attributable deposition are not linked, *e.g.*, the 99th percentile of the percent of total deposition attributable to U.S. EGUs is based on the distribution of total Hg deposition, and the 99th percentile of U.S. EGU-attributable Hg deposition is based on the distribution of U.S. EGU-attributable deposition. These percentiles do not occur at the same watershed.

Table 6—Comparison of Total and U.S. EGU-Attributable Hg Deposition

Statistic	2005		2016	
	Total Hg deposition	U.S. EGU-attributable Hg deposition	Total Hg deposition	U.S. EGU-attributable Hg deposition
Mean	19.41	0.89	18.66	0.34
Median	17.25	0.24	16.59	0.15
75th percentile	23.69	1.07	22.83	0.46
90th percentile	30.78	2.38	29.90	0.85
95th percentile	36.85	3.60	35.16	1.18
99th percentile	58.32	7.77	56.23	2.41

* Statistics are based on CMAQ results interpolated to the watershed-level and are calculated using all [approx.] 88,000 watersheds in the U.S.

To give a better idea of the relationship between total deposition and U.S. EGU-attributable deposition, we also summarize the percent of total Hg deposition attributable to U.S. EGUs (by percentile) in Table 7. Table 7 shows the high variability in the percent contribution from U.S. EGU Hg emissions. Tables 6 and 7 cannot be directly compared, as the watershed with the 99th percentile U.S. EGU-attributable deposition is not the same watershed as the watershed with the 99th percentile U.S. EGU-attributable fraction of total Hg deposition. A watershed can have a high U.S. EGU-attributable fraction of total deposition and still have overall low Hg deposition.

Table 7—Comparison of Percent of Total Hg Deposition Attributable to U.S.

Statistic	2005 (percent)	2016 (percent)
Mean	5	2
Median	1	1
75th percentile	6	3
90th percentile	13	5
95th percentile	18	6
99th percentile	30	11

* Values are based on CMAQ results interpolated to the watershed-level and reflect trends across all [approx.] 88,000 watersheds in the U.S.

U.S. EGUs are estimated to contribute up to 30 percent of total Hg deposition in 2005 and up to 11 percent in 2016.

EPA estimates the relationship between the EGU-attributable Hg deposition and EGU-attributable fish tissue MeHg concentrations using an assumption of linear proportionality based on the agency's MMaps

approach. The MMaps assumption specifies that, under certain conditions (*e.g.*, Hg air deposition is the primary source of Hg loading to a watershed and near steady-state conditions have been reached), a fractional change in Hg deposition to a watershed will ultimately be reflected in a matching proportional change in the levels of MeHg in fish. [98] [99] This

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[98] The MMaps approach implements a simplified form of the IEM-2M model applied in EPA's Mercury Study Report to Congress (Mercury Maps—A Quantitative Spatial Link Between Air Deposition and Fish Tissue Peer Reviewed Final Report. U.S. EPA, Office of Water, EPA-823-R-01-009, September, 2001). By simplifying the assumptions inherent in the freshwater ecosystem models that were described in the Report to Congress, the MMaps model showed that these models converge at a steady-state solution for MeHg concentrations in fish that are proportional to changes in Hg inputs from atmospheric deposition (*e.g.*, over the long term fish concentrations are expected to decline proportionally to declines in atmospheric loading to a watershed). This solution only applies to situations where air deposition is the only significant source of Hg to a water body, and the physical, chemical, and biological characteristics of the ecosystem remain constant over time. EPA recognizes that concentrations of MeHg in fish across all ecosystems may not reach steady state and that ecosystem conditions affecting Hg dynamics are unlikely to remain constant over time. EPA further recognizes that many water bodies, particularly in areas of historic gold and Hg mining in western states, contain significant non-air sources of Hg (note, however, that as described below, we have excluded those watersheds containing gold mines or with other non-EGU related anthropogenic Hg releases exceeding specified thresholds).

[99] The risk assessment is not designed to track the detailed temporal profile associated with changes in fish tissue MeHg levels following changes in Hg deposition. Rather, we are focusing on estimating risk in the future, assuming that near steady state conditions have been reached (following a simulated change in Hg deposition). Additional detail regarding the temporal profile issue and other related factors (*e.g.*, methylation potential across

assumption holds in watersheds where air deposition is the primary source of Hg loadings, and as a result, watersheds where this is not the case are removed from the risk analysis. The practical application of the MMaps approach is that U.S. EGUs will account for the same proportion of fish tissue MeHg in a watershed as they do for Hg deposition. MMaps is discussed in greater detail in section 1.3 and Appendix E of the National Scale Mercury Risk Assessment TSD. Patterns of U.S. EGU-attributable fish tissue MeHg concentrations are summarized in Table 8 of this preamble. Table 8 of this preamble compares total and U.S. EGU-attributable fish tissue MeHg concentrations for the 2005 and 2016 scenarios by watershed percentile.

Table 8—Comparison of Total and U.S. EGU-Attributable Fish Tissue Me Hg Concentrations for 2005 and 2016

Statistic	Fish tissue MeHg concentration (ppm)			
	2005		2016	
	Total	U.S. EGU-attributable	Total	U.S. EGU-attributable
Mean	0.31	0.024	0.29	0.008
50th Percentile	0.23	0.014	0.20	0.005
75th Percentile	0.39	0.032	0.36	0.011
90th Percentile	0.67	0.056	0.63	0.019
95th Percentile	0.91	0.079	0.87	0.026
99th Percentile	1.34	0.150	1.29	0.047

Because the focus of this analysis is on higher-consumption self-caught fisher populations active at inland freshwater locations, we identified surveys of

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watersheds) is discussed in Section 1.3 and in Appendix E of the National Scale Mercury Risk Assessment TSD).

higher consumption fishing populations active at inland freshwater rivers and lakes within the continental U.S. to inform the selection of consumption rate scenarios.[100] Information on the studies used to develop the high end fish consumption scenarios for the risk analysis is provided in the National Scale Mercury Risk Assessment TSD.

Generally all of the studies identified high-end percentile consumption rates (90th to 99th percentiles for the populations surveyed) ranging from approximately one fish meal every few days to a fish meal a day (*i.e.*, 120 grams per day (g/day) to greater than 500 g/day fish consumption). We used this trend across the studies to support application of a generalized female high-end fish consumption

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[100] A number of criteria had to be met for a study to be used in providing explicit consumption rates for the high-end fisher populations of interest in this analysis. For example, studies had to provide estimates of self-caught fish consumption and not conflate these estimates with consumption of commercially purchased fish. Furthermore, these studies had to focus on freshwater fishing activity, or at least have the potential to reflect significant contributions from that category, such that the fish consumption rates provided in a study could be reasonably applied in assessing freshwater fishing activity. Studies also had to provide statistical estimates of fish consumptions (*i.e.*, means, medians, 90th percentiles, etc). Given our interest in higher-end consumption rates, the studies also had to either provide upper percentile estimates, or support the derivation of those estimates (*e.g.*, provide medians and a standard deviations). Studies of activity at specific watersheds (*e.g.*, creel surveys), while informative in supporting the presence of higher-end consumption rates, could not be used as the basis for defining our high-end consumption rates since there would be greater uncertainty in extrapolating activity at a specific river or lake more broadly to fishing populations in a region. Therefore, we focused on studies characterizing fishing activity more broadly than at a specific fishing location.

scenario (high-end female consumer scenario) across most of the 2,461 watersheds.[101]

iv. Risk Related to Exposure to MeHg in Fish and Assessment of Contribution of U.S. EGUs to MeHg Exposure and Risk

For the scenario representing high-end female fish consumption, we estimated total exposure to MeHg at each of the 2,461 watersheds.[102] Estimates of total Hg exposure were generated by combining 75th percentile fish tissue values with the consumption rates for female subsistence fishers. A cooking loss factor (reflecting the fact that the preparation of fish can result in increased Hg concentrations) was also included in exposure calculations.[103]

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[101] Reflecting the fact that higher levels of self-caught fish consumption (approaching subsistence) have been associated with poorer populations, we only assessed this generalized high-end female consumer scenario at those watersheds located in U.S. Census tracts with at least 25 individuals living below the poverty line (this included the vast majority of the 2,461 watersheds and only a handful were excluded due to this criterion).

[102] As noted earlier, each high-end fish consuming female population included in the analysis was assessed for a subset of these watersheds, depending on which of those watersheds intersected a U.S. Census tract containing a "source population" for that fish consuming population. Of the populations assessed, the low-income female subsistence fishing population scenario was assessed for the largest portion (2,366) of the 2,461 watersheds.

[103] Morgan, J.N., M.R. Berry, and R.L. Graves. 1997. "Effects of Commonly Used Cooking Practices on Total Mercury Concentration in Fish and Their Impact on Exposure Assessments." Journal of Exposure Analysis and Environmental Epidemiology 7(1):119-133.

Our estimates of total percent of watersheds where female subsistence fishing populations may be at risk from exposure to U.S. EGU-attributable MeHg are as high as 28 percent. The upper end estimate of 28 percent of watersheds reflects the 99th percentile fish consumption rate for that population, and a benchmark of 5 percent U.S. EGU contribution to total Hg deposition in the watershed. Any contribution of Hg emissions from EGUs to watersheds where potential exposures from total Hg deposition exceed the RfD is a hazard to public health, but for purposes of our analyses we evaluated only those watersheds where we determined EGUs contributed 5 percent or more to deposition to the watershed. EPA believes this is a conservative approach given the increasing risks associated with incremental exposures above the RfD. Of the total number of watersheds where populations may be at risk from exposure to EGU-attributable MeHg, we estimate that up to 22 percent of watersheds included in this analysis could potentially have populations at risk based on consideration of the U.S. EGU attributable fraction (*e.g.*, 5, 10, 15, or 20 percent) of total Hg deposition over watersheds with total risk judged to represent a public health hazard (MeHg total exposure greater than the RfD).[104] Of the total number of watersheds where populations may be at risk from exposures to U.S. EGU-attributable MeHg, we estimate that up to 12 percent of watersheds included in this analysis could potentially have populations at risk because the U.S. EGU incremental contribution to exposure is above the RfD,

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[104] Because of the MMaps assumption of linear proportionality between deposition and exposures, a 5 percent U.S. EGU contribution to deposition will produce an equivalent 5 percent U.S. EGU contribution to MeHg exposures.

even before consideration of contributions to exposures from U.S. non-EGU and non-U.S. sources. In other words, for this 12 percent of watersheds, even if there were no other sources of Hg exposure, exposures associated with deposition attributable to U.S. EGUs would place female high-end consumers above the MeHg RfD. The upper end estimate of 12 percent of watersheds reflects a scenario using the 99th percentile fish consumption rate.

The two estimates of percent of watersheds where populations may be at risk from EGU-attributable Hg do not sum to the total estimates of 28 percent because some watersheds where U.S. EGUs contribute greater than 5 percent to total Hg deposition also have U.S. EGU attributable exposures that exceed the RfD without consideration of exposures from other U.S. and non-U.S. Hg sources.

Exposures based on the 99th percentile consumption rate represent close to maximum potential individual risk estimates. These consumption rates are based on data reported by fishers in surveys, and, thus, represent actual consumption rates in U.S. populations. There are also a number of case studies in other locations, such as poor urban areas, which provide additional evidence that high fish consumption occurs in a number of locations

throughout the U.S.[105] [106] [107] [108] However, EPA does not have sufficiently complete data on the specific locations where these high self-caught fish consuming populations reside and fish, and as a result, there is increased uncertainty about the prevalence of populations who are high-end consumers of fish caught in the set of watersheds included in the analysis. Populations matching the high-end fish consumption scenario could be restricted to a subset of these watersheds, or could be more heavily focused at watersheds with higher or lower U.S. EGU-attributable fish tissue MeHg (and consequently higher or lower U.S. EGU-attributable risk).

With regard to the other fisher populations included in the full risk assessment described in the TSD (Vietnamese, Laotians, Hispanics, blacks and whites in the southeast, and tribes in the vicinity of the Great Lakes), our risk estimates suggests that the high-end

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[105] Burger, J., K. Pflugh, L. Lurig, L. Von Hagen, and S. Von Hagen. 1999. Fishing in Urban New Jersey: Ethnicity Affects Information Sources, Perception, and Compliance. Risk Analysis 19(2): 217-229.

[106] Burger, J., Stephens, W., Boring, C., Kuklinski, M., Gibbons, W.J., & Gochfield, M. (1999). Factors in exposure assessment: Ethnic and socioeconomic differences in fishing and consumption of fish caught along the Savannah River. Risk Analysis, 19(3).

[107] Chemicals in Fish Report No. 1: Consumption of Fish and Shellfish in California and the United States Final Draft Report. Pesticide and Environmental Toxicology Section, Office of Environmental Health Hazard Assessment, California Environmental Protection Agency, July 1997.

[108] Corburn, J. (2002). Combining community-based research and local knowledge to confront asthma and subsistence-fishing hazards in Greenpoint/Williamsburg, Brooklyn, New York. Environmental Health Perspectives, 110(2).

female consumer assessed at the national-level generally provides coverage (in terms of magnitude of risk) for all of these fisher populations except blacks and whites in the southeast.[109] [110]

v. Variability and Uncertainty (Including Discussion of Sensitivity Analyses)

There are some uncertainties in EPA's analyses which could lead to under or over prediction of risk to public health from U.S. EGU Hg emissions. Based on sensitivity analyses we have conducted, we conclude that even under different assumptions about the applicability of the MMaps proportionality assumption, Hg from U.S. EGUs constitutes a hazard to public health due to the percent of watersheds where U.S. EGUs cause or contribute to exposures to MeHg above the RfD.

Key sources of uncertainty potentially impacting the risk analysis include: (1) Uncertainty in predicting Hg deposition over watersheds using CMAQ; (2) uncertainty in predicting which watersheds will be subject to high-end fishing activity and the nature of that activity (*e.g.*, frequency of repeated activity at a

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[109] Specifically, upper percentile risk estimates for the high-end female consumer assessed at the national level were notably higher than matching percentile estimates for the Hmong, Vietnamese, Hispanic, and Tribal populations. By contrast, risk estimates for whites in the southeast were somewhat higher than the high-end female consumer, while risk estimates for blacks in the southeast were notably higher (see summary of risk estimates in the TSD supporting this finding).

[110] The National Scale Mercury Risk Assessment TSD discusses the greater uncertainty in characterizing the magnitude of high-end fish consumption for these specialized populations due, in particular, to the lower sample sizes associated with the survey data (see Appendix C, Table C-1).

given watershed and the types/sizes of fish caught); (3) uncertainty in using MMaps to apportion exposure and risk between different sources, including U.S. EGUs, and predicting changes in fish tissue MeHg levels for future scenarios; and (4) potential under-representation of watersheds highly impacted by U.S.-attributable Hg deposition due to limited MeHg sampling. In the National Scale Mercury Risk Assessment TSD, we describe in greater detail key sources of uncertainty impacting the risk analysis, including their potential impact on the risk estimates and the degree to which their potential impact is characterized as part of the analysis.

As part of the analysis, we have also completed a number of sensitivity analyses focused on exploring the impact of uncertainty related to the application of the MMaps approach in apportioning exposure and risk estimates between sources (U.S. EGU and total) and in predicting changes in fish tissue MeHg levels.[111] These sensitivity analyses evaluated: (1) The effect of including watersheds that may be disproportionately impacted by non-air Hg sources;[112] and (2) the

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[111] The sensitivity analyses completed for the risk assessment focused on assessing sources of uncertainty associated with the application of the MMaps approach, because this was a critical element in the risk assessment and identified early on as a key source of potential uncertainty. Given the schedule of the analysis, we did not have time to complete a full influence analysis to identify those additional modeling elements that might introduce significant uncertainty and therefore should be included in a sensitivity analysis. Appendix F, Table F-2 of the Mercury Risk TSD provides a qualitative discussion of key sources of uncertainty and their potential impact on the risk assessment.

[112] In addition to non-air Hg sources of loadings, some regions of concern may also have longer lag period associated with the

representativeness of the MMaps approach, which was tested for lakes, when applied to streams and rivers (in the analysis, the MMaps was applied to watersheds including a mixture of streams, rivers, and lakes). The results of the limited sensitivity analyses we were able to conduct suggest that uncertainties due to application of MMaps would not affect our finding that U.S. EGU-attributable Hg deposition poses a hazard to public health.

We also examined the potential for under-representation of watersheds highly impacted by U.S.-attributable Hg deposition due to limited MeHg sampling, by identifying watersheds that did not have fish tissue MeHg samples, but had U.S. EGU-attributable Hg deposition at least as high as watersheds that were identified as being at risk of potential exposures greater than the RfD. Comparing the pattern of U.S. EGU-attributable Hg deposition across all watersheds with that for watersheds containing fish tissue MeHg data shows that while we have some degree of coverage for watersheds with high U.S. EGU-attributable deposition, this coverage is limited, especially in areas of Pennsylvania which have high levels of U.S. EGU-attributable deposition. For this reason, we believe that the actual number of watersheds where populations may be at risk from exposures to U.S. EGU-attributable MeHg could be substantially larger than the number estimated based on the available fish tissue MeHg sampling data.

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linkage between Hg deposition such that the fish tissue MeHg levels we are using are actually associated with older historical Hg deposition patterns.

d. U.S. EGU Case Studies of Cancer and Non-Cancer Inhalation Risks for Non-Hg HAP

EPA conducted 16 case studies to estimate the potential for human health impacts from current emissions of HAP other than Hg from EGUs. A refined chronic inhalation risk assessment was performed for each case study facility. The results of this analysis were that 4 (out of 16) facilities posed a lifetime cancer risk of greater than 1 in 1 million (the maximum was 10 in 1 million) and 3 more posed a risk at 1 in 1 million. Risk was driven by Ni (the oil-fired unit) and Cr<+6> (the coal-fired units).

i. Case Study Selection

An initial set of eight case study facilities was selected based on several factors. First, we considered facilities with the highest estimated cancer and non-cancer risks using the 2005 National Emissions Inventory (NEI) data and the Human Exposure Model (HEM). The 2005 NEI data were used because the initial set of case study facilities was selected before we received the bulk of the emissions data from the 2010 ICR. Other factors considered in the selection included whether facilities had implemented emission control measures since 2005, and their proximity to residential areas. After the receipt of more data through the 2010 ICR, additional case study facilities were selected, based on the magnitude of emissions, heat input values (throughput), and level of emission control. There were a total of 16 case study facilities, 15 that use coal as fuel, and 1 that uses oil.

ii. Methods

Annual emissions estimates for each EGU (including those in the initial set of case study facilities) were developed using data from the 2010

ICR. The results for the initial set indicated that Ni, Cr<+6>, and As were the cancer risk drivers, and that non-cancer risks did not produce any hazard index (HI) estimates exceeding one. Although the non-cancer risks were low (the maximum chronic noncancer HI was 0.4), they were driven by emissions of Ni, As, and HCl. For the reasons discussed above, emissions were estimated only for Ni, Cr<+6>, and As for the additional case study facilities. Additional details on the emissions used in the modeling are provided in a supporting memorandum to the docket for this action (Non-Hg Case Study Chronic Inhalation Risk Assessment for the Utility MACT "Appropriate and Necessary" Analysis) (Non-Hg Memo). For each of the 16 case study facilities, we conducted refined dispersion modeling with EPA's AERMOD modeling system (U.S. EPA, 2004) to calculate annual ambient concentrations. Average annual concentrations were calculated at census block centroids.

We calculated the MIR for each facility as the cancer risk associated with a continuous lifetime (24 hours per day, 7 days per week, and 52 weeks per year for a 70-year period) exposure to the maximum concentration at the centroid of an inhabited census block, based on application of the unit risk estimate from EPA's IRIS, which is a human health assessment program that evaluates quantitative and qualitative risk information on effects that may result from exposure to environmental contaminants. For Ni compounds, we used 65 percent of the IRIS URE for nickel subsulfide. The determination of this value is discussed in the Non-Hg Memo, and the value is receiving peer review as discussed in section later. To assess the risk of non-cancer health effects from chronic exposures, following the approach

recommended in EPA's Mixtures Guidelines,[113] [114] we summed the HQs for all HAP that affect a common target organ system to obtain the HI for that target organ system (target-organ-specific HI, or TOSHI). The HQ for chronic exposures is the estimated chronic exposure (again, based on the estimated annual average ambient concentration at each nearby census block centroid) divided by the chronic non-cancer reference level, which is usually the EPA reference concentration (RfC). In cases where an IRIS RfC is not available, EPA utilizes the following prioritized sources for chronic dose-response values: (1) The Agency for Toxic Substances and Disease Registry (ATSDR) Minimum Risk Level (MRL), and (2) the California Environmental Protection Agency chronic Reference Exposure Level (REL). In this assessment, we used the IRIS RfC values for Cr<+6> and HCl, the ATSDR MRL for Ni compounds, and the California Environmental Protection Agency REL for As.

iii. Results

The highest estimated lifetime cancer risk from any of the 16 case study facilities was 10 in 1 million (1 x 10<-5>), driven by Ni emissions from the 1 case study facility with oil-fired units. For the facilities with coal-fired units, there were 3 with maximum cancer risks greater than 1 in 1 million (the highest was 8 in 1 million), all driven by Cr<+6>, and there were 4 with maximum cancer risks at 1 in 1 million. All of the

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[113] U.S. EPA, 1986, Guidelines for the Health Risk Assessment of Chemical Mixtures, EPA-630-R-98-002. http://www.epa.gov/NCEA/raf/pdfs/chem_mix/chemmix_1986.pdf.

[114] U.S. EPA, 2000. Supplementary Guidance for Conducting Health Risk Assessment of Chemical Mixtures. EPA-630/R-00-002. http://www.epa.gov/ncea/raf/pdfs/chem_mix/chem_mix_08_2001.pdf.

facilities had non-cancer TOSHI values less than one, with a maximum HI value of 0.4 (also driven by Ni emissions from the one case study facility with oil-fired units). The maximum chronic impacts of HCl emissions were all less than 10 percent of its chronic RfC. Because of uncertainties in their emission rates, other acid gases (Cl[2], HF, and HCN) were not included in the assessment of noncancer impacts. Because EGUs are not generally co-located with other source categories, facility-wide HAP emissions and risks are equal to those associated with the EGU source category.

The cancer risk estimates from this assessment indicate that the EGU source category is not eligible for delisting under CAA section 112(c)(9)(B)(i), which specifies that a category may be delisted only when the Administrator determines "* * * that no source in the category (or group of sources in the case of area sources) emits such HAP in quantities which may cause a lifetime risk of cancer greater than one in one million to the individual in the population who is most exposed to emissions of such pollutants from the source * * *" We note that, because these case studies do not cover all facilities in the category, and because our assessment does not include the potential for impacts from different EGU facilities to overlap one another (*i.e.*, these case studies only look at facilities in isolation), the maximum risk estimates from the case studies may underestimate true maximum risks.

e. Peer-Review of Quantitative Risk Analyses

The Agency has determined that the National-Scale Mercury Risk Analysis supporting EPA's 2011 review of U.S. EGU health impacts should be peer-reviewed. In addition, the Agency has determined that the characterization of the chemical speciation for the

emissions of Cr and Ni should be peer-reviewed. The Agency has evaluated the other components of the analyses supporting this finding and determined that the remaining aspects of the case study analyses for non-Hg HAP use methods that have already been subject to adequate peer-review. As a result, the Agency is limiting the peer-review to the National-Scale Mercury Risk Analysis and the speciation of emissions for Cr and Ni. Due to the court-ordered schedule for this proposed rule, EPA will conduct these peer reviews as expeditiously as possible after issuance of this proposed rule and will publish the results of the peer reviews and any EPA response to them before the final rule.

4. Qualitative Assessment of Potential Environmental Risks From Exposures of Ecosystems Through Hg and Non-Hg HAP Deposition

Adverse effects on fish and wildlife have been observed to be occurring today which are the result of elevated exposures to MeHg, although these effects have not been quantitatively assessed.

Elevated MeHg concentrations in fish and wildlife can occur not only in areas of high Hg deposition. Elevated MeHg concentrations can also occur in diverse locations, including watersheds that receive average or even relatively low Hg deposition, but are particularly sensitive to Hg pollution, for example, they have higher than average methylation rates due to high levels of sulfur deposition. Such locations are characterized by moderate deposition levels that have generated high Hg concentrations in biota compared to the surrounding landscape receiving a similar Hg loading. These Hg-sensitive watersheds readily transport inorganic Hg, convert the inorganic Hg to MeHg, and bioaccumulate this MeHg through the food

web. Areas of enhanced MeHg in fish and wildlife are not constrained to a single Hg source, because ecosystems respond to the combined effects of Hg pollution from multiple sources.

A review of the literature on effects of Hg on reproduction in fish[115] reports adverse reproductive effects for numerous species including trout, bass (large and smallmouth), northern pike, carp, walleye, salmon, and others from laboratory and field studies. Mercury also affects avian species. In previous reports[116] much of the focus has been on large fish-eating species, in particular the common loon. Breeding loons experience significant adverse effects including behavioral (reduced nest-sitting), physiological (flight feather asymmetry) and reproductive (chicks fledged/territorial pair) effects.[117]

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[115] Crump, Kate L., and Trudeau, Vance L. Mercury-induced reproductive impairment in fish. Environmental Toxicology and Chemistry. Vol. 28, No. 5, 2009.

[116] U.S. Environmental Protection Agency (EPA). 1997. Mercury Study Report to Congress. Volume V: Health Effects of Mercury and Mercury Compounds. EPA-452/R-97-007. U.S. EPA Office of Air Quality Planning and Standards, and Office of Research and Development.

U.S. Environmental Protection Agency (U.S. EPA). 2005. *Regulatory Impact Analysis of the Final Clean Air Mercury Rule*. Office of Air Quality Planning and Standards, Research Triangle Park, NC., March; EPA report no. EPA-452/R-05-003. Available on the Internet at http://www.epa.gov/ttn/ecas/regdata/RIAs/mercury_ria_final.pdf.

[117] Evers, David C., Savoy, Lucas J., DeSorbo, Christopher R., Yates, David E., Hanson, William, Taylor, Kate M., Siegel, Lori S., Cooley, John H. Jr., Bank, Michael S., Major, Andrew, Munney, Kenneth, Mower, Barry F., Vogel, Harry S., Schoch, Nina, Pokras, Mark, Goodale, Morgan W., Fair, Jeff. Adverse

Other fish-eating bird species such as the white ibis and great snowy egret experience a range of adverse effects due to exposure to Hg. The white ibis has been observed to have decreased foraging efficiency[118] and decreased reproductive success and altered pair behavior.[119] These effects include significantly more unproductive nests, male/male pairing, reduced courtship behavior and lower nestling production by exposed males. In egrets, Hg has been implicated in the decline of the species in south Florida[120] and studies show liver and possibly kidney effects.[121] Insectivorous birds have also been shown to suffer adverse effects due to Hg exposure. Songbirds such as Bicknell's thrush, tree swallows and the great tit have shown reduced reproduction, survival, and changes in

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effects from environmental mercury loads on breeding common loons. Ecotoxicology. 17:69-81, 2008.

[118] Adams, Evan M., and Frederick, Peter C. Effects of methylmercury and spatial complexity on foraging behavior and foraging efficiency in juvenile white ibises (Eudocimus albus). Environmental Toxicology and Chemistry. Vol 27, No. 8, 2008.

[119] Frederick, Peter, and Jayasena, Nilmini. Altered pairing behavior and reproductive success in white ibises exposed to environmentally relevant concentrations of methylmercury. Proceedings of The Royal Society B. doi: 10-1098, 2010.

[120] Sepulveda, Maria S., Frederick, Peter C., Spalding, Marilyn G., and Williams, Gary E. Jr. Mercury contamination in free-ranging great egret nestlings (Ardea albus) from southern Florida, USA. Environmental Toxicology and Chemistry. Vol. 18, No.5, 1999.

[121] Hoffman, David J., Henny, Charles J., Hill, Elwood F., Grover, Robert A., Kaiser, James L., Stebbins, Katherine R. Mercury and drought along the lower Carson River, Nevada: III. Effects on blood and organ biochemistry and histopathology of snowy egrets and black-crowned night-herons on Lahontan Reservoir, 2002-2006. Journal of Toxicology and Environmental Health, Part A. 72:20, 1223-1241, 2009.

singing behavior. Exposed tree swallows produced fewer fledglings,[122] lower survival,[123] and had compromised immune competence.[124] The great tit has exhibited reduced singing behavior and smaller song repertoire in areas of high contamination/[125]

In mammals, adverse effects from Hg including mortality have been observed in mink and river otter, both fish eating species. Other adverse effects may include increased activity, poorer maze performance, abnormal startle reflex, and impaired escape and avoidance behavior.[126] EPA is also concerned about the potential impacts of HCl and other acid gas emissions on the environment. When HCl gas encounters water in the atmosphere, it forms an acidic solution of hydrochloric acid. In areas where the deposition of acids derived from emissions of sulfur and NO[X] are causing aquatic and/or terrestrial acidification, with accompanying ecological impacts, the deposition of hydrochloric acid would further exacerbate these

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[122] Brasso, Rebecka L., and Cristol, Daniel A. Effects of mercury exposure in the reproductive success of tree swallows (Tachycineta bicolor). Ecotoxicology. 17:133-141, 2008.

[123] Hallinger, Kelly K., Cornell, Kerri L., Brasso, Rebecka L., and Cristol, Daniel A. Mercury exposure and survival in free-living tree swallows (Tachycineta bicolor). Ecotoxicology. Doi: 10.1007/s10646-010-0554-4, 2010.

[124] Hawley, Dana M., Hallinger, Kelly K., Cristol, Daniel A. Compromised immune competence in free-living tree swallows exposed to mercury. Ecotoxicology. 18:499-503, 2009.

[125] Gorissen, Leen, Snoeijs, Tinne, Van Duyse, Els, and Eens, Marcel. Heavy metal pollution affects dawn singing behavior in a small passerine bird. Oecologia. 145:540-509, 2005.

[126] Scheuhammer, Anton M., Meyer Michael W., Sandheinrich, Mark B., and Murray, Michael W. Effects of environmental methylmercury on the health of wild birds, mammals, and fish. Ambio. Vol.36, No.1, 2007.

impacts. Recent research[127] has, in fact, determined that deposition of airborne HCl has had a greater impact on ecosystem acidification than anyone had previously thought, although direct quantification of these impacts remains an uncertain process.

5. Potential for Deposition "Hotspots" in Areas Near U.S. EGUs

Although it has been characterized and addressed as a global issue, Hg from U.S. EGUs is shown to deposit in higher quantities close to emission sources, and around some sources can be as high as 3 times the regional average deposition. EPA evaluated the potential for "hot spot" deposition near U.S. EGU emission sources on a national scale, based on the CMAQ modeled Hg deposition for 2005 and 2016.[128] We calculated the excess deposition within 50 km of U.S. EGU sources by first calculating the average U.S. EGU attributable Hg deposition within a 500 km radius around the U.S. EGU source. This deposition represents the likely regional contribution around the EGU. We then calculated the average U.S. EGU attributable Hg deposition within 50 km of the U.S. EGUs to characterize local deposition plus regional deposition near the EGU facility. Excess local deposition is then the 50 km radius average deposition minus the 500 km radius average deposition. Summary statistics for the excess local deposition are provided in Table 9 of this preamble. Table 9 of this

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[127] Evans, Chris D., Monteith, Don, T., Fowler, David, Cape, J. Neil, and Brayshaw, Susan. Hydrochloric Acid: An Overlooked Driver of Environmental Change, Env. Sci. Technol., DOI: 10.1021/es10357u.

[128] More details are provided in the National Scale Mercury Risk Assessment TSD.

preamble shows both the mean excess deposition around all U.S. EGUs, and the mean excess deposition around just the top 10 percent of Hg emitting U.S. EGUs. Table 9 of this preamble also shows the excess Hg deposition as a percent of the average regional deposition to provide context for the magnitude of the local excess deposition. In 2005, for all U.S. EGU, the excess was around 120 percent of the average deposition, while for the top 10 percent of Hg emitting U.S. EGU, local deposition was around 3.5 times the regional average. By 2016, although the absolute excess deposition falls, the local excess still remains around 3 times the regional average for the highest 10 percent of Hg emitting U.S. EGUs.

Table 9—Excess Local Deposition of Hg Based on 2005 CMAQ Modeled Hg Deposition

	50 km-Radius-average excess local deposition values ([mu]g/m(2M))	
	Mean across EGUs (percent of regional average deposition)	
	2005	2016
All U.S. EGU sites with Hg emissions > 0 (672 sites)	1.65 (119%)	0.36 (93%)
Top ten percent U.S. EGU in Hg emissions (67 sites)	4.89 (352%)	1.18 (302%)

This analysis shows that there is excess deposition of Hg in the local areas around EGUs, especially those with high Hg emissions. Although this is not necessarily indicative of higher risk of adverse effects from consumption of MeHg contaminated fish from waterbodies around the U.S. EGUs, it does indicate an increased chance that Hg from U.S. EGUs will impact local waterbodies around the EGU sources, and not just impact regional deposition.

6. Emissions Controls for Emissions of Hg and Non-Hg HAP Are Available and Effective

Analyses of currently available control technologies for Hg, acid gases, and non-Hg metal HAP show that significant reductions in these pollutants can be achieved from EGUs with significant coincidental reductions in the emissions of other pollutants as well.

a. Availability of Hg Emissions Control Options

The control of Hg in a coal combustion flue gas is highly dependent upon the form (or species) of the Hg. The Hg can be present in one of three forms: as Hg<0>, as a vapor of Hg<+> <2> (*e.g.*, mercuric chloride, Hg(Cl[2])), or as Hg[P] (*e.g.*, adsorbed on fly ash or unburned carbon). The specific form of the Hg in the flue gas will strongly influence the effectiveness of available control technology for Hg control. The form (or "speciation") of the Hg is determined by the flue gas chemistry and by the time-temperature profile in the post combustion environment. During coal combustion, Hg is released into the exhaust gas as Hg<0>. This vapor may then continue through the flue gas cleaning equipment and exit the stack as gaseous Hg<0> or it may be oxidized to Hg<+> <2> compounds (such as HgCl[2]) via homogeneous (gas-gas) or heterogeneous (gas-solid) reactions. The primary homogeneous oxidation mechanism is the reaction with gas-phase chlorine (Cl radical or possibly, HCl) to form HgCl[2]. Although this mechanism is thermodynamically favorable, it is thought to be kinetically limited due to rapid cooling of the flue gas stream. Heterogeneous oxidation reactions occur on the surface of fly ash and unburned carbon. It is thought that in-duct chlorination of the surface of the fly ash, unburned carbon, or injected activated carbon sorbent is the first step to heterogeneous oxidation and

surface binding of vapor-phase Hg<0> in the flue gas stream (*i.e.*, the formation of Hg[P]).

Mercury control can occur as a "co-benefit" of conventional control technologies that have been installed for other purposes. Particulate Hg can be effectively removed along with other flue gas PM (including non-Hg metal HAP) in the primary or secondary PM control device. For units using electrostatic precipitators (ESPs), the effectiveness will depend upon the amount of Hg[P] entering the ESP. Units that burn coals with higher levels of native chlorine and that produce more unburned carbon can see good Hg removal in the ESP. Fabric filters (FF) have been shown to provide very high levels of control when there is adequate halogen to convert the Hg to the oxidized form. Units with wet FGD scrubbers can achieve high levels of Hg control—provided that the Hg is present in the oxidized (*i.e.*, the soluble) form. A selective catalytic reduction (SCR) catalyst can enhance the Hg removal by catalytically converting Hg<0> to Hg<+> <2>, making it more soluble and more likely to be captured in the scrubber solution. Halogen additives (usually bromide salts, but chloride salts may also be used) can also be added directly to the coal or injected into the boiler to enhance the oxidation of Hg.

Activated carbon injection (ACI) is the most successfully demonstrated Hg-specific control technology. In this case, a powdered AC sorbent is injected into the duct upstream of the primary or a secondary PM control device. The carbon is injected to maximize contact with the flue gas. Mercury binds on the surface of the carbon to form Hg[P], which is then removed in the PM control device. Conventional (*i.e.*, non-halogenated) AC is effective when capturing Hg

that is already predominantly in the oxidized state or when there is sufficient flue gas halogens to promote oxidation of the Hg on the AC surface. Pre-halogenated (*i.e.*, brominated) AC has been shown to be very effective when used in combination with low chlorine coals (such as U.S. western subbituminous coals). Activated carbons can suffer from poor performance when used with high sulfur coals. Firing high sulfur coals (especially when an SCR is also used) can result in sulfur trioxide (SO[3]) vapor in the flue gas stream. The SO[3] competes with Hg for binding sites on the surface of the AC (or unburned carbon) and limits the effectiveness of the injected AC. An SO[3] mitigation technology—such as dry sorbent injection (DSI, *e.g.*, trona or hydrated lime)—applied upstream of the ACI can minimize this effect.

Mingling of AC with the fly ash can affect the viability for use of the captured fly ash as an additive in concrete production. Use of the TOXECON(TM) configuration can keep the fly ash and the AC separate. This configuration consists of the primary PM control device (ESP or FF) followed by a secondary downstream pulsejet FF. The AC is injected prior to the secondary FF. The fly ash is captured in the primary PM control device and the AC and Hg are captured in the downstream secondary FF.

b. Availability of PM or Metal HAP Emissions Control Options

Electrostatic precipitators and FFs are the most commonly applied PM control technologies in U.S. coal-fired EGUs. Newer units have tended to install FFs, which usually provide better performance than ESPs. An existing facility that wants to upgrade the PM control may choose to replace the current equipment with newer, better performing equipment.

The facility may also consider installation of a downstream secondary PM control device—such as a secondary FF. A wet ESP (WESP) can be installed downstream of a wet FGD scrubber for control of condensable PM.

c. Availability of Acid Gas Emissions Control Options

Acid gases are likely to be removed in typical FGD systems due to their solubility or their acidity (or both). The acid-gas HAP—HCl, HF, and HCN (representing the "cyanide compounds")—are water-soluble compounds, more soluble in water than is SO[2]. This indicates that HCl, HF, and HCN should be more easily removed from a flue gas stream in a typical FGD system than will SO[2], even when only plain water is used. Hydrogen chloride is also a strong acid and will react easily in acid-base reactions with the caustic sorbents (*e.g.*, lime, limestone) that are commonly used in FGD systems. Hydrogen fluoride is a weaker acid, having a similar acid dissociation constant as that of SO[2]. Cyanide is the weakest of these acid gases. In the slurry streams, composed of water and sorbent (*e.g.*, lime, limestone) used in both wet-scrubber and dry spray dryer absorber FGD systems, acid gases and SO[2] are absorbed by the slurry mixture and react to form alkaline salts. In fluidized bed combustion (FBC) systems, the acid gases and SO[2] are adsorbed by the sorbent (usually limestone) that is added to the coal and an inert material (*e.g.*, sand, silica, alumina, or ash) as part of the FBC process. Hydrogen chloride and HF have also been shown to be effectively removed using DSI where a dry, alkaline sorbent (*e.g.*, hydrated lime, trona, sodium carbonate) is injected upstream of a PM control device. Chlorine in the fuel coal may also partition in small amounts to Cl[2]. This is normally a

very small fraction relative to the formation of HCl. Limited testing has shown that Cl[2] gas is also effectively removed in FGD systems. Although Cl[2] is not strictly an acidic gas, it is grouped here with the "acid gas HAP" because it is controlled using the same technologies.

d. Expected Impact of Available Controls on HAP Emissions from EGUs

In 2016, EGUs are projected to account for an estimated 45 percent of anthropogenic Hg (excluding fires) in the continental U.S. Application of available Hg controls in 2016 that would be required under section 112 reduces Hg emissions from 29 down to 6 tons, achieving a 23 tpy reduction of Hg from EGUs, which results in a 79 percent reduction in U.S. EGU emissions, and a 36 percent reduction of total anthropogenic Hg emissions nationally.

In 2016, EGUs are projected to account for 53 percent of total U.S. anthropogenic HCl. Application of available HCl controls in 2016 that would be required under section 112 achieves a 68,000 tpy reduction in HCl emissions (a 91 percent reduction in EGU emissions), resulting in a 49 percent reduction of anthropogenic emissions nationally.

Metal HAP emissions are a component of PM, and are expected to be reduced along with PM as a result of application of PM controls. In 2016, application of controls required under section 112 is expected to provide an average reduction in PM for the continental U.S. of 38 percent. Although no specific projection of metals is available for 2016, applying the 38 percent reduction in PM to the 2010 ICR emissions levels of

anthropogenic metals,[129] results in reductions of approximately 430 tons of metals per year.[130]

EPA believes these projected reductions in Hg, acid gases, and metal HAP emissions demonstrate the effectiveness of available controls.

6. Consideration of the Role of U.S. EGU Hg Emissions in the Global Effort To Decrease Hg Loadings in the Environment

This would allow the U.S. to demonstrate effective technologies to reduce Hg; such leadership could provide confidence to other countries that they can succeed in meeting their commitments. Mercury pollution is a significant international environmental challenge, and it is well understood that efforts that reduce Hg emissions in other countries will reduce Hg that impacts U.S. public health and the environment. Recognizing this, EPA and others in the U.S. Government are actively involved in international efforts to reduce Hg pollution. These efforts include global negotiations aimed at concluding a legally-binding agreement to reduce Hg that were initiated in February 2009 under the UNEP.[131] Negotiation of the agreement is not expected to be completed until early 2013. Once the international process is complete, the agreement must be ratified domestically before the

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[129] It is generally assumed that the same types of controls that reduce PM will also reduce metals, because they are components of the PM.

[130] This value is 38 percent of 1,140 tons, which is the total tonnage of the metals listed in Table 5, based on the 2010 ICR emissions data.

[131] Governing Council of the United Nations Environment Programme http://www.unep.org/hazardoussubstances/Mercury/Negotiations/Mandates/tabid/3321/language/en-US/Default.aspx.

agreement will become binding in the U.S. The agreement is expected to cover major man-made sources of air Hg emissions, including coal-fired EGUs. Current negotiations are considering the application of best available technologies and practices to reduce air Hg emissions significantly. Regulations such as the proposed rule demonstrate the U.S. commitment to addressing the global Hg problem by decreasing the largest source of Hg emissions in the U.S. and serve to encourage other countries to address Hg emissions from their own sources.

7. It Remains Appropriate and Necessary To Regulate EGUs To Address Public Health and Environmental Hazards Associated With Emissions of Hg and Non-Hg HAP From EGUs

The extensive analyses summarized above confirm that it remains appropriate and necessary today to regulate EGUs under section 112. It is appropriate to regulate emissions from coal- and oil-fired EGUs under CAA section 112 because: (1) Hg and non-Hg HAP continue to pose a hazard to public health, and U.S. EGU emissions cause and/or contribute to this hazard; (2) Hg and some non-Hg HAP pose a hazard to the environment; (3) U.S. EGU emissions, accounting for 45 percent of U.S. Hg emissions, are still the largest domestic source of U.S. Hg emissions (by 2016, EPA projects that U.S. EGU Hg emissions will be over 6 times larger than the next largest source, which is iron and steel manufacturing), as well as the largest source of HCl and HF emissions, and a significant source of other HAP emissions; (4) Hg emissions from individual EGUs leads to hot spots of deposition in areas directly surrounding those individual EGUs, and, thus, deposition is not solely the result of

regionally transported emissions, and will not be adequately addressed through reductions in regional levels of Hg emissions, requiring controls to be in place at all U.S. EGU sources that emit Hg; (5) Hg emissions from EGUs affect not only deposition, exposures, and risk today, but may contribute to future deposition, exposure and risk due to the processes of reemission of Hg that occur given the persistent nature of Hg in the environment—the delay in issuing Hg regulations under section 112 has already resulted in several hundred additional tons of Hg being emitted to the environment, and that Hg will remain part of the global burden of Hg; and (6) effective controls for Hg and non-Hg HAP are available for U.S. EGU sources.

EPA concludes that Hg emissions from U.S. EGUs are a public health hazard today due to their contribution to Hg deposition that leads to potential MeHg exposures above the RfD. EPA also concludes that U.S. EGU Hg emissions contribute to environmental concentrations of Hg that are harmful to wildlife and can affect production of important ecosystem services, including recreational hunting and fishing, and wildlife viewing. EPA further concludes that non-Hg HAP emissions from U.S. EGU are a public health hazard because they contribute to elevated cancer risks.

Finally, EPA concludes that U.S. EGU's HCl and HF emissions contribute to acidification in sensitive ecosystems and, therefore, pose a risk of adverse effects on the environment.

a. U.S. EGU Hg Emissions Continue To Pose a Hazard to Public Health and the Environment

The CAA does not define what constitutes a hazard to public health. As noted earlier, the agency must use

its scientific and technical expertise to determine what constitutes a hazard to public health in the context of Utility Hg emissions. Congress did provide guidance as to what it considered an important benchmark for public health hazards, particularly in regard to Hg. In section 112(n)(1)(C), Congress required the NIEHS to determine "the threshold level of Hg exposure below which adverse human health effects are not expected to occur." This threshold level is represented by the RfD, and as such, the RfD is the benchmark for determining hazards to public health that is most consistent with Congress's interpretation of adverse health effects. As a result, our assessment of the hazard to public health posed by U.S. EGU Hg emissions is focused on comparisons to the RfD of exposures caused or contributed to by U.S. EGU Hg emissions.

As described above, almost all (98 percent) of the more than 2,400 watersheds for which we have fish tissue data exceed the RfD, above which there is the potential for an increased risk of adverse effects on human health. U.S. EGU-attributable deposition of Hg contributes to a large number of those watersheds in which total potential exposures to MeHg from all sources exceed the RfD and, thus, pose a hazard to public health. For our analysis, we focused on the watersheds to which EGUs contributed at least 5 percent of the total Hg deposition and related MeHg exposures at a watershed, or contributed enough Hg deposition resulting in potential MeHg exposures above the RfD, regardless of the additional deposition from other sources of Hg deposition. We believe this is a conservative approach because any contribution of Hg to watersheds where potential exposures to MeHg exceed the RfD poses a public health hazard. Thus, because we are finding a large percentage of

watersheds with populations potentially at risk even using this conservative approach, we have confidence that emissions of Hg from U.S. EGUs are causing a hazard to public health, as we believe that there are additional watersheds that have contributions at lower percent benchmarks.

In total, 28 percent of sampled watersheds have populations that are potentially at risk from exposure to MeHg based on the contribution of U.S. EGUs, either because U.S. EGU attributable deposition is sufficient to cause potential exposures to exceed the reference dose even before considering the deposition from other U.S. and non-U.S. sources, or because the U.S. EGU attributable deposition contributes greater than 5 percent of total deposition and total exposure from all sources is greater than the reference dose. At the 99th percentile fish consumption level for subsistence fishers, 22 percent of sampled watersheds where total potential exposures to MeHg exceed the RfD have a contribution from U.S. EGUs of at least 5 percent of Hg deposition.

Although the most complete estimate of potential risk is based on total exposures to Hg, including that due to deposition from U.S. EGU sources, U.S. non-EGU sources, and global sources, the deposition resulting from U.S. EGU Hg emissions is large enough in some watersheds that persons consuming contaminated fish would have exposures that exceed the RfD even before taking into account the deposition from other sources. At the 99th percentile fish consumption level for subsistence fishers, in 12 percent of the sampled watersheds, U.S. EGUs are responsible for deposition that causes the RfD to be exceeded, even before considering the additional deposition from other sources.

In addition, we believe the estimate of where populations may be at risk from U.S. EGU-attributable Hg deposition is likely understated because the data on fish tissue MeHg concentrations is limited in some regions of the U.S., such as Pennsylvania, with very high U.S. EGU attributable Hg deposition, and it is possible that watersheds with potentially high MeHg exposures were excluded from the risk analysis.[132] In addition, due to limitations in our models and available data, we have not estimated risks in near-coastal waters, and some of these waters, including the Chesapeake Bay, have EGU-attributable Hg deposition.

Further, scientific studies have found strong evidence of adverse impacts on species of fish-eating birds with high bird-watching value, including loons, white ibis, and great snowy egrets. Studies have also shown adverse effects on insect-eating birds including many songbirds. Adverse effects in fish-eating mammals, such as mink and otter, include neurological responses (impaired escape and avoidance behavior) which can influence survival rates. Because EGUs contribute to Hg deposition in the U.S., we reasonably conclude that EGUs are contributing to the identified adverse environmental effects.

Mercury emitted into the atmosphere persists for years, and once deposited, can be reemitted into the atmosphere due to a number of processes, including forest fires and melting of snow packs. As a result, Hg emitted today can have impacts for many years. In

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[132] An analysis of the impact of sampling location limitations on coverage of high U.S. EGU deposition watersheds is provided in the National Scale Mercury Risk Assessment TSD.

fact, Hg emitted by U.S. EGUs in the past, including over the last decade, is still having impacts on concentrations of Hg in fish today. Failing to control Hg emissions from U.S. EGU sources will result in long term environmental loadings of Hg, above and beyond those loadings caused by immediate deposition of Hg within the U.S. Although we are not able to quantify the impact of U.S. EGU emissions on the global pool of Hg, U.S. EGUs do contribute to that global pool. Controlling Hg emissions from U.S. EGUs helps to reduce the potential for environmental hazard from Hg now and in the future. These findings independently support a determination that it is appropriate to regulate HAP emissions from EGUs.

b. U.S. EGU Non-Hg HAP Emissions Continue To Pose a Hazard to Public Health and the Environment

EPA recently conducted 16 case studies of U.S. EGUs for which we had 2007 to 2009 emissions data (based on the 2010 ICR) and that we anticipated would have relatively higher emissions of non-Hg HAP compared to other U.S. EGUs. Of the 16 facilities modeled, 4 facilities, 3 coal and 1 oil facility, have estimated risks of greater than 1 in 1 million for the most exposed individual. Although section 112(n)(1)(A) does not specify what constitutes a hazard to public health for the purposes of the appropriate and necessary finding, CAA section 112(c)(9) is instructive. As explained in section III.A above, for carcinogenic HAP, section 112(c)(9) contains a test for delisting source categories based on lifetime risk of cancer. That test reflects Congress' view as to the level of health effects associated with HAP emissions that Congress thought warranted continued regulation under section 112. Specifically, section 112(c)(9) provides that a source category can be

delisted only if no source emits HAP in quantities which may cause a lifetime risk of cancer greater than 1 in 1 million to the most exposed individual. As noted above, the results of the case study risk analysis confirm that sources in the EGU source category emit HAP in quantities that cause a lifetime risk of cancer greater than 1 in 1 million. Given Congress' determination that categories of sources which emit HAP resulting in a lifetime cancer risk greater than 1 in 1 million should not be removed from the section 112(c) source category list and should continue to be regulated under 112, we believe risks above that level represent a hazard to public health such that it is appropriate to regulate EGUs under section 112.

Although our case studies did not identify significant chronic non-cancer risks from acid gas emissions from the specific EGUs assessed, the Administrator remains concerned about the potential for acid gas emissions to add to already high atmospheric levels of other chronic respiratory toxicants and to environmental loading and degradation due to acidification. EGUs emit over half of the nationwide emissions of HCl and HF, based on 2010 emissions estimates. In addition, given that many sensitive ecosystems across the country are experiencing acidification, it is appropriate to reduce emissions of this magnitude which carry the potential to aggravate acidification. The Administrator concludes that, in addition to the regulation of non-Hg HAP which cause elevated cancer risks, it is appropriate to regulate those HAP which are not known to cause cancer but are known to contribute to chronic non-cancer toxicity and environmental degradation, such as the acid gases.

These findings independently support a determination that it is appropriate to regulate HAP emissions from EGUs.

c. Effective Controls Are Available To Reduce Hg and Non-Hg HAP Emissions

Particle-bound Hg can be effectively removed along with other flue gas PM (including non-Hg metal HAP) in primary or secondary PM control devices. Electrostatic precipitators, FF, and wet FGD scrubbers are all effective at removing Hg, with the degree of effectiveness depending on the specific characteristics of the EGU and fuel types. These devices are all effective in removing metal HAP as well. Activated carbon injection is the most successfully demonstrated Hg-specific control technology, although performance may be reduced when used with high sulfur coals. Acid gases are readily removed in typical FGD systems due to their solubility or their acidity (or both). The availability of controls for HAP emissions from EGUs supports the appropriate finding because sources will be able to reduce their emissions effectively and, thereby, reduce the hazards posed by HAP emissions from EGUs.

d. The Administrator Finds That It Remains Necessary To Regulate Coal- and Oil-Fired EGUs Under CAA Section 112

EPA determined that in 2016 the hazards posed to human health and the environment by HAP emissions from EGUs will not be addressed; therefore, it is necessary to regulate EGUs under section 112. In addition, it is necessary to regulate EGUs under section 112 because the only way to ensure permanent reductions in U.S. EGU emissions of HAP and the

associated risks to public health and the environment is through standards set under section 112.

The Agency first evaluates whether it is necessary to regulate HAP emissions from EGUs "after imposition of the requirements of the CAA." As explained above, we interpret that phrase to require the Agency to consider only those requirements that Congress directly imposed on EGUs through the CAA as amended in 1990 and for which EPA could reasonably predict HAP emission reductions at the time of the Study. Nonetheless, the Agency recognizes that it has discretion to look beyond the Utility Study in determining whether it is necessary to regulate EGUs under section 112. Because several years have passed since the December 2000 Finding, we conducted an additional, updated analysis, examining a broad array of diverse requirements.

Specifically, we analyzed EGU HAP emissions remaining in 2016. Our analysis included the proposed Transport Rule; CAA section 112(g); the ARP; Federal, state, and citizen enforcement actions related to criteria pollutant emissions from EGUs; and some state rules related to criteria pollutant emissions. We included state requirements and citizen and state enforcement action settlements associated with criteria pollutants because those requirements may have a basis under the CAA. We did not, however, conduct an analysis to determine whether the requirements are, in fact, based on requirements of the CAA. As such, we believe there may be instances where we should not have considered certain state rules or state and citizen suit enforcement settlements in our analysis, because those requirements are based solely in state law and are not required by Federal law. We did not include in our analysis any state-only

requirements or voluntary actions to reduce HAP emissions because we knew there was no Federal backstop for those requirements and actions.

Our analysis confirms that Hg emissions from EGUs remaining in 2016 still pose a hazard to public health and the environment and, for that reason, it remains necessary to regulate EGUs under section 112. Specifically, we estimate that U.S. EGU emissions of Hg after imposition of the requirements of the CAA will be 29 tpy in 2016, the same as the level of Hg emitted today. As we stated above, we evaluated the hazards to public health and the environment from Hg based on the estimated Hg emissions in 2016 and found that a hazard exists. Because a hazard remains after imposition of the requirements of the CAA, it is necessary to regulate EGUs.

It is necessary to regulate HAP emissions from EGUs, even though the hazards from Hg will not be resolved through regulation under section 112. EPA finds that incremental reductions in Hg are important because as exposure above the RfD increases the likelihood and severity of adverse effects increases.

EGUs are the largest source of Hg in the U.S. and, thus, contribute to the risk associated with exposure to MeHg. By reducing Hg emissions from U.S. EGUs, this proposed rule will help to reduce the risk to public health and the environment from Hg exposure.

We also find that it is necessary to regulate EGUs under section 112 based on non-Hg HAP emissions because we cannot be certain that the identified cancer risks attributable to EGUs will be addressed through imposition of the requirements of the CAA. In addition, the environmental hazards posed by

acidification will not be fully addressed through imposition of the CAA.

We also find it necessary to regulate EGUs because regulation under section 112 is the only way to ensure that HAP emissions reductions that have been achieved since 2005 remain permanent.

The difference between the 53 ton 2005 estimate and the 2010 ICR-based estimate of total EGU emissions may be overstated. While EPA has estimated 2010 total EGU Hg emissions of 29 tons based on data from the 2010 ICR database, this may underestimate total 2010 EGU Hg emissions due to the fact that emission factors used to develop the estimates may not accurately account for larger emissions from units with more poorly performing emission controls. The 2010 ICR by which the data used to develop the factors was collected was designed to provide the agency the data to determine the appropriate MACT levels and was not designed to collect data to fully characterize all units' Hg emissions, particularly those that might have poorly performing controls. EPA tested only 50 randomly selected units that were not selected for testing as best performing units (the bottom 85 percent of units), and we used that small sample to attempt to characterize the lower performing units. Because the 50 units were randomly selected, we do not believe we have sufficiently characterized the units that have poorly performing controls. In addition, the methodology for estimating the 2005 and 2010 emission estimates are not the same. The 2005 estimate is based on control configurations as of 2002, therefore, it does not reflect reductions due to control installations that took place between 2002 and 2005. As a result, the apparent difference between 2005 and 2010 is overstated. There

are real factors that explain why Hg reductions would have occurred between 2005 and 2010. The actual reductions between 2005 and 2010 are attributable to state Hg regulations and to CAIR and Federal enforcement actions that achieve Hg reductions as a co-benefit of controls for PM, NO[X], and SO[2] emissions. However, there are no national, Federally binding regulations for Hg. State Hg regulations can potentially change or be revoked without EPA approval, and reductions that occur as a co-benefit of criteria pollutant regulations can also change. Furthermore, companies can change their criteria pollutant compliance strategies and use methodologies that do not achieve the same level of Hg or other HAP co-benefit (*e.g.*, purchasing allowances in a trading program instead of using add-on controls).

As with Hg, the most recent data on U.S. EGU HCl and HF emissions show a significant reduction between 2005 and 2010. These reductions in HCl and HF are the co-benefit of controls installed to meet other CAA requirements, including enforcement actions, and to a lesser extent, state regulations. There is no guarantee other than regulation under section 112 that these significant decreases in HCl and HF emissions will be permanent. Although we do not have estimates for the remaining HAP emitted from EGUs, we believe it is likely that such emissions have also decreased between 2005 and 2010. Thus, the Administrator finds it necessary to regulate HAP emissions from EGUs to ensure that HAP emissions reductions are permanent.

Finally, direct control of Hg emissions affecting U.S. deposition is only possible through regulation of U.S. emissions; we are unable to control global emissions directly. Although the U.S. is actively involved in

international efforts to reduce Hg pollution, the ability of the U.S. to argue effectively in these negotiations for strong international policies to reduce Hg air emissions depends in large part on our domestic policies, programs and regulations to control Hg.

All of these findings independently support a finding that it is necessary to regulate EGUs under section 112.

Therefore, given the Agency's finding that it remains appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112, EPA is confirming its inclusion of coal- and oil-fired EGUs on the list of source categories regulated under CAA section 112(c).

8. Implications of Hazards to Public Health for Children and Environmental Justice Communities

Children are at greatest risk of adverse health effects from exposures to Hg, and this risk is amplified for children in minority and low income communities who subsist on locally-caught fish. Today's proposed rule is therefore an important step in addressing disparate impacts on children and environmental justice (EJ) communities.

Children are more vulnerable than adults to many HAP, because of differences in physiology, higher per body weight breathing rates and consumption, rapid development of the brain and bodily systems, and behaviors that increase chances for exposure. Even before birth, the developing fetus may be exposed to HAP through the mother that affect development and permanently harm the individual. Infants and children breathe at much higher rates per body weight than adults, with infants under one year of age having

a breathing rate up to five times that of adults.[133] In addition, children breathe through their mouths more than adults and their nasal passages are less effective at removing pollutants, which leads to a higher deposition fraction in their lungs.[134] Crawling and frequent hand-to-mouth activity lead to infants' higher levels of ingestion of contaminants deposited onto soil or in dust. Infants' consumption of breast milk can pass along high levels of accumulated persistent bioaccumulative pollutants from their mothers. Children's dietary intake also exceeds that of adults, per body weight, posing a potential added risk from persistent HAP that accumulate in food. In addition to the greater exposure, the less-well developed detoxification pathways and rapidly developing systems and organs put children at potentially greater risk.

Mercury is the HAP from EGUs of most concern to early life stages. The adverse affects of Hg on developing neuropsychological systems is well-established and permanent. The prenatal period of development has been established to be the most sensitive lifestage to the neurodevelopmental effects of

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[133] U.S. Environmental Protection Agency. 2006. *Revision of the metabolically-derived ventilation rates within the Exposure Factors Handbook*. (External review draft) Washington, DC: Office of Research and Development. EPA/600/R-06/129A. http://oaspub.epa.gov/eims/eimscomm.getfile?p_download_id=460261.

[134] Foos, B., M. Marty, J. Schwartz, W. Bennett, J. Moya, A. M. Jarabek, and A. G. Salmon. 2008. Focusing on children's Inhalation Dosimetry and Health Effects for Risk Assessment: An Introduction. *J Toxicol Environ Health* 71A: 149-165.

MeHg.[135] Children who are exposed to low concentrations of MeHg prenatally are at increased risk of poor performance on neurobehavioral tests, such as those measuring attention, fine motor function, language skills, visual-spatial abilities, and verbal memory.[136] [137] Impaired cognitive development from exposures to MeHg prenatally and in early childhood affect the individual into adulthood, by affecting learning and potential future earnings, and contributing to behavioral problems.

Other HAP related to EGU emissions present greater risks to children as well. For example, mutagenic carcinogens such as Cr<+6> have a larger impact during young lifestages, given the rapid development of the corporal systems.[138] Exposure at a young age to these carcinogens could lead to a higher risk of developing cancer later in life.

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[135] National Academy of Sciences. 2000. *Toxicological Effects of Methylmercury*. Washington, DC: National Academy Press. http://books.nap.edu/catalog/9899.html?onpi_newsdoc071100.

[136] P. Grandjean, P. Weihe, R.F. White, F. Debes, S. Araki, K. Yokoyama, K. Murata, N. Sorensen, R. Dahl and P.J. Jorgensen. 1997. Cognitive deficit in 7-year-old children with prenatal exposure to methylmercury. *Neurotoxicology and Teratology* 19 (6):417-28.

[137] T. Kjellstrom, P. Kennedy, S. Wallis and C. Mantell. 1986. *Physical and mental development of children with prenatal exposure to mercury from fish. Stage 1: Preliminary tests at age 4.* Sweden: Swedish National Environmental Protection Board.

[138] U.S. Environmental Protection Agency. 2005. *Supplemental Guidance for Assessing Susceptibility from Early-Life Exposure to Carcinogens*. Washington, DC: Risk Assessment Forum. EPA/630/R-03/003F http://www.epa.gov/raf/publications/pdfs/childrens_supplement_final.pdf

The adverse effects of individual non-Hg HAP may be more severe for children, particularly the youngest age groups, than adults. A number of epidemiologic studies suggest that children are more vulnerable than adults to lower respiratory symptoms associated with PM.[139] [140] Non-Hg metal HAP may behave similarly to particulate matter, at least in terms of the deposition fraction that reaches children's lungs. As with Hg, Pb and Cd are known to affect children's neurologic development. A meta-analysis of seven studies has shown an association between exposure to formaldehyde, another HAP of concern, and development of asthma in children.[141]

Within communities overburdened with environmental exposures, the youngest lifestages are likely the most vulnerable. Looking at the health effects for children in those communities can be an important part of appropriately assessing community risks.

EPA has also considered the effects of this rule on EJ communities. The nature of exposures to Hg is such that populations with high levels of self-caught fish consumption are likely to be disproportionately affected. EPA's risk analysis identified many EJ communities, including Laotian, Vietnamese,

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[139] Pope, C.A. and D.W. Dockery. 1992. Acute health effects of PM10 pollution on symptomatic and asymptomatic children. *Am Rev Respir Dis* 145: 1123-1128.

[140] Gauderman, W.J., R. McConnell, F. Gilliland, S. London, et al. 2000. Association between air pollution and lung function growth in Southern California children. *Am J Respir Crit Care Med* 162: 1283-1390.

[141] McGwinn, G. Jr., J. Lienert, and J.I. Kennedy Jr. 2010. Formaldehyde Exposure and Asthma in Children: A Systematic Review. *Environ Health Perspect* 118: 313-317.

Hispanic, African-American, tribal, and low income communities, as having higher levels of subsistence fishing activities. Consequently, individuals in these communities are potentially exposed to levels of MeHg in fish that may result in these individuals' exposure exceeding the RfD. These EJ populations are thus at higher risk for the health effects associated with exposures to MeHg, which include impacts on neurological functions that can cause children to struggle in school. In EJ populations which often face numerous other stressors that can result in lower educational performance, the additional burdens imposed by exposure to Hg may cause significant and long-lasting impacts on children that continue into adulthood, affecting learning potential and measures of IQ, including future earnings and indicators of quality of life.

9. The Analysis Supporting the 2005 Action Was Subject to Technical Limitations and These Flaws Undermine the Basis for the 2005 Action

In 2005, EPA conducted a set of technical analyses to support a revision to the 2000 appropriate and necessary finding.[142] In those analyses, EPA made several assumptions that were not justified based on scientific or technical grounds, and which we have corrected in our technical analysis supporting our current confirmatory finding that it is appropriate and necessary to regulate coal- and oil-fired EGUs under section 112.

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[142] U.S. EPA. 2005. Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls.

a. Interpretation of the MeHg Reference Dose and Incremental U.S. EGU-Attributable Exposures

In the 2005 analysis, EPA made the following statement:

> The RfD provides a useful reference point for comparisons with measured or modeled exposure. The Agency defines the RfD as an exposure level below which the Agency believes exposures are likely to be without an appreciable risk over a lifetime of exposure. For the purposes of assessing population exposure due to EGUs, we create an index of daily intake (IDI). The IDI is defined as the ratio of exposure due solely to EGUs to an exposure of 0.1 [mu]g/kg bw/day. The IDI is defined so that an IDI of 1 is equal to an incremental exposure equal to the RfD level, recognizing that the RfD is an absolute level, while the IDI is based on incremental exposure without regard to absolute levels. Note that an IDI value of 1 would represent an absolute exposure greater than the RfD when background exposures are considered.[143]

Upon further consideration, EPA concludes that it did not have a scientific or technical justification for creating a metric other than the HQ[144] to compare U.S. EGU-attributable exposures to the RfD. As EPA recognized in 2005, the RfD is an absolute level above which the potential risks of exposures increase, based on total exposures to MeHg. The concept of the IDI was created by EPA in 2005 solely to support its

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[143] U.S. EPA. 2005. Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls.

[144] The HQ is the ratio of observed or modeled exposures to the RfD.

interpretation that it must assess hazards to public health solely based on U.S. EGU emissions with no consideration of exposures to MeHg arising from other sources of Hg deposition. As noted above, nothing in section 112(n)(1)(A) prohibits consideration of HAP emissions from U.S. EGUs in conjunction with HAP emissions from other sources of HAP, including sources outside the U.S. Indeed, such an approach would ignore the manner in which the public is actually exposed to HAP emission. By focusing on whether incremental exposures attributable to U.S. EGU Hg emissions exceeded the RfD without consideration of other exposures, EPA implied that U.S. EGU Hg emissions were not causing a hazard to public health even though such emissions were increasing risks in locations where the RfD was already exceeded due to total exposures from all Hg sources, including U.S. EGU emissions. This is a serious flaw in EPA's 2005 assessment, due to reasons we discuss below.

Ninety-eight percent of watersheds with fish tissue MeHg samples have Hg deposition levels such that total potential exposure to MeHg exceeds the RfD, and many have exposures that are many times the RfD.[145] As a result, in almost all watersheds with fish tissue MeHg samples, any additional Hg will increase potential risk. Thus, U.S. EGU-attributable Hg deposition is contributing to increased potential risk. The Agency believes the assessment of potential risk due to Hg emissions from U.S. EGUs must consider both the extent to which U.S. EGUs contribute to such risk along with other sources, and the extent to which U.S. EGU-attributable deposition leads to exposures

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[145] *See* the National Scale Mercury Risk Assessment Technical Support Document.

that exceed the RfD even before considering the contributions of other sources of Hg. The Agency has conducted such an evaluation in the national-scale MeHg risk analysis presented above. In 2005, as a result of relying on a flawed, non-scientific approach for comparing MeHg exposures to the RfD, and a failure to consider cumulative risk characterization metrics, EPA incorrectly determined that U.S. EGU emissions of Hg did not constitute a hazard to public health. As discussed above, EPA has revised this determination and concluded that U.S. EGU Hg emissions are a hazard to public health because they cause exposures to exceed the RfD or contribute to exposures in watersheds where total exposures to MeHg exceed the RfD.

b. Interpretation of Populations Likely To Be at Risk and Conclusions Regarding Acceptable Risk

In addition to developing a flawed exposure indicator based on only U.S. EGU attributable exposure (the IDI), EPA also erred in finding that exposures above the RfD (an IDI greater than 1) did not pose an "unacceptable risk" (*e.g.*, did not pose a hazard to public health). EPA cited three reasons for the finding in 2005: (1) Lack of confidence in the risk estimates; (2) lack of seriousness of the health effects of MeHg; and (3) small size of the population at risk and low probability of risks in that population. EPA was not justified in making its determination based on these three factors.

In the 2005 Action, EPA cited the underpinnings of the RfD as introducing a degree of conservatism. In fact, however, as discussed above, EPA has stated consistently, including in the RfD issued in 2001, that the RfD for Hg is a level above which there is the potential for increased risk. Only at levels at or below

the RfD does the Agency maintain that exposures are without *significant* risk. EPA's interpretation in 2005 was a departure from prior EPA policy as it concerns exposures to Hg and was in error.

In the 2005 Action, EPA identified risk of poor performance on neurobehavioral tests, such as those measuring attention, fine motor function, language skills, visual-spatial abilities (like drawing), and verbal memory as the primary health effects of MeHg exposures. Although not stated explicitly, it is implicit in the 2005 Action that EPA did not consider these health effects to be serious. The Agency did not, and could not have, provided any scientific or policy rationale for dismissing these serious public health effects. For example, as mentioned above, there are potentially serious implications of the identified effects on learning potential and measures of IQ, including future earnings and indicators of quality of life. EPA was not justified in dismissing these health effects as not serious without providing evidence or justification, which it could not do based on the information available at the time or today.

In the 2005 Action, EPA made several statements in the technical analysis suggesting that the probability that an IDI of 1 would be exceeded (*e.g.*, that U.S. EGU attributable exposures would be greater than the RfD) was low due to the rare occurrence of high consumption rate populations in high deposition watersheds. The 2005 analysis showed that 15 percent of watersheds would have U.S. EGU-attributable potential exposures that were twice the RfD for the highest fish consumption rates. EPA dismissed this high percent of watersheds by stating that those high fish consumption rates would only occur in Native American populations, and that those populations

lived in locations that were not heavily impacted by U.S. EGU Hg deposition.

Information was available at the time of the 2005 analysis indicating that other populations besides Native Americans engaged in subsistence fishing activities that would result in consumption rates similar to Native Americans. EPA chose to selectively use information only on Native American consumption rates and erroneously concluded that subsistence fishing activities would not occur in a wider set of locations. This choice was in error, as EPA should have investigated whether other subsistence populations could fish in locations heavily impacted by U.S. EGU emissions (*e.g.*, watersheds with the top 15 percent of U.S. EGU-attributable fish tissue MeHg levels). A search of the literature available in 2005 reveals several studies that identified additional fishing populations with subsistence or near subsistence consumption rates, including urban fishing populations (including low-income populations),[146] [147] [148]

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[146] Burger, J., K. Pflugh, L. Lurig, L. Von Hagen, and S. Von Hagen. 1999. Fishing in Urban New Jersey: Ethnicity Affects Information Sources, Perception, and Compliance. Risk Analysis 19(2): 217-229.

[147] Burger, J., Stephens, W., Boring, C., Kuklinski, M., Gibbons, W.J., & Gochfield, M. (1999). Factors in exposure assessment: Ethnic and socioeconomic differences in fishing and consumption of fish caught along the Savannah River. Risk Analysis, 19(3).

[148] Chemicals in Fish Report No. 1: Consumption of Fish and Shellfish in California and the United States Final Draft Report. Pesticide and Environmental Toxicology Section, Office of Environmental Health Hazard Assessment, California Environmental Protection Agency, July 1997.

Laotian communities,[149] and Hispanics. In fact, EPA participated in 1999 in a project investigating exposures of poor, minority communities in New York City to a number of contaminants including Hg, and should thus have been aware that these populations can have very high consumption rates.[150] If EPA had conducted a thorough investigation in 2005, it should have concluded that populations with the potential for subsistence-level fish consumption rates occur in many watersheds, and, thus, could not have concluded that exposures above the RfD (IDI greater than 1) were not likely.

Thus, based on the errors EPA made in the 2005 Action related to evaluating the risks from MeHg exposures attributable to U.S. EGUs, EPA's technical determination in 2005 that risks were acceptable based on that analysis was not justified. As a result the technical determination in 2005 which supported the finding of no public health hazard, and the determination that it was not appropriate or necessary to regulate HAP from U.S. EGUs was in error.

IV. Summary of This Proposed NESHAP

This section summarizes the requirements proposed in this proposed rule. Our rationale for the proposed requirements is provided in Section V of this preamble.

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[149] Tai, S. 1999. "Environmental Hazards and the Richmond Laotian American Community: A Case Study in Environmental Justice." Asian Law Journal 6: 189.

[150] Corburn, J. (2002). Combining community-based research and local knowledge to confront asthma and subsistence-fishing hazards in Greenpoint/Williamsburg, Brooklyn, New York. Environmental Health Perspectives, 110(2).

A. What source categories are affected by this proposed rule?

This proposed rule affects coal- and oil-fired EGUs.

B. What is the affected source?

An existing affected source for this proposed rule is the collection of coal- and oil-fired EGUs within a single contiguous area and under common control. A new affected source is a coal- or oil-fired EGU for which construction or reconstruction began after May 3, 2011.

CAA section 112(a)(8) defines an EGU as:

a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also an electric utility steam generating unit.

If an EGU burns coal (either as a primary fuel or as a supplementary fuel), or any combination of coal with another fuel (except as noted below), the unit is considered to be coal fired under this proposed rule. If a unit is not a coal-fired unit and burns only oil, or oil in combination with another fuel other than coal (except as noted below), the unit is considered to be oil fired under this proposed rule. As noted below, EPA is proposing a definition to determine whether the combustion unit is "fossil fuel fired" such that it is an EGU for purposes of this proposed rule. The unit must be capable of combusting more than 73 megawatt-electric (MWe) (250 million British thermal units per hour, MMBtu/hr) heat input (equivalent to 25 MWe

electrical output) of coal or oil. In addition, using the construct of the definition of "oil-fired" from the ARP, we are proposing that the unit must have fired coal or oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years to be considered a "fossil fuel fired" EGU subject to this proposed rule. If a new or existing EGU is not coal- or oil-fired, and the unit burns natural gas exclusively or natural gas in combination with another fuel where the natural gas constitutes 90 percent or more of the average annual heat input during the previous 3 calendar years or 85 percent or more of the annual heat input during any 1 of those calendar years, the unit is considered to be natural gas-fired and would not be subject to this proposed rule. As discussed later, we believe that this definition will address those situations where either an EGU fires coal or oil on only a limited basis or co-fires limited amounts of coal or oil with other non-fossil fuels (*e.g.*, biomass).

To the extent a unit combusts solid waste, that unit is not an EGU under section 112, but rather would be subject to CAA section 129.

The Small Entity Representatives (SERs) serving on the Small Business Advocacy Review Panel (SBAR) established under the Small Business Regulatory Enforcement Fairness Act (SBREFA) suggested that EPA consider developing an area-source (*i.e.*, those EGUs emitting less than 10 tpy of any one HAP or less than 25 tpy of any combination of HAP) vs. major-source (*i.e.*, those EGUs emitting 10 tpy or more of any one HAP or 25 tpy of more of any combination of HAP) distinction for this source category. The proposed rule

treats all EGUs the same and proposes MACT standards for all units.

Nothing in the CAA requires that we issue GACT standards for area sources. Indeed, here, the data show that similar HAP emissions and control technologies are found on both major and area sources greater than 25 MWe. In fact, because of the significant number of well-controlled EGUs of all sizes, we believe it would be difficult to make a distinction between MACT and GACT. Moreover, EPA believes the standards for area source EGUs should reflect MACT, rather than GACT, because there is no essential difference between area source and major source EGUs with respect to emissions of HAP. There are EGUs that are physically quite large that are area sources, and EGUs that are small that are major sources. Both large and small EGUs are represented in the MACT floor pools for acid gas, Hg, and non-Hg metal HAP. Finally, given that EPA is regulating both major and area source EGUs at the same time in this rulemaking, a common control strategy consequently appears warranted for these emissions.

If area sources tend to be very different from major sources and the capacity to control those sources is different, we could exercise our discretion under section 112(d)(5) to set GACT standards for area sources. But, as explained above, that is not the case here. Accordingly, we believe it is appropriate to set MACT standards for both major and area source EGUs. EPA solicits comment on its proposed approach. Specifically, we solicit comments on whether there would be a basis for considering area sources to be significantly different from major sources with respect to issues relevant to standard setting. Commenters should also explain the basis of their

suggested approach and how that approach would lead to similar health and environmental benefits, including data that would underpin a GACT analysis.[151]

C. Does this proposed rule apply to me?

This proposed rule applies to you if you own or operate a coal- or oil-fired EGU as defined in this proposed rule.

D. Summary of Other Related DC Circuit Court Decisions

In March 2007, the DC Circuit Court issued an opinion (Sierra Club v. EPA, 479 F.3d 875 (DC Cir. 2007)) (Brick MACT) vacating and remanding CAA section 112(d) NESHAP for the Brick and Structural Clay Ceramics source categories. Some key holdings in that case were:

• Floors for existing sources must reflect the average emission limitation achieved by the best-performing 12 percent of existing sources, not levels

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[151] As we have explained in other rules, determining what constitutes GACT involves considering the control technologies and management practices that are generally available to the area sources in the source category. We also consider the standards applicable to major sources in the same industrial sector to determine if the control technologies and management practices are transferable and generally available to area sources. In appropriate circumstances, we may also consider technologies and practices at area and major sources in similar categories to determine whether such technologies and practices could be considered generally available for the area source category at issue. Finally, in determining GACT for a particular area source category, we consider the costs and economic impacts of available control technologies and management practices on that category.

EPA considers to be achievable by all sources (479 F.3d at 880-81);

• EPA cannot set floors of "no control." The DC Circuit Court reiterated its prior holdings, including *National Lime Ass'n. v. EPA* (233 F.3d625 (DC Cir. 2000)) (*National Lime II*), confirming that EPA must set floor standards for all HAP emitted by the source, including those HAP that are not controlled by at-the-stack control devices (479 F.3d at 883);

• EPA cannot ignore non-technology factors that reduce HAP emissions. Specifically, the DC Circuit Court held that "EPA's decision to base floors exclusively on technology even though non-technology factors affect emissions violates the Act." (479 F.3d at 883.) The DC Circuit Court also reiterated its position stated in *Cement Kiln Recycling Coalition v. EPA*, 255 F.3d 855 (DC Cir. 2001) that CAA section 112(d)(3) "requires floors based on the emission level actually achieved by the best performers (those with the lowest emission levels)."

Based on the *Brick MACT* decision, we believe a source's performance resulting from the presence or absence of HAP in fuel materials must be accounted for in establishing floors (*i.e.*, a low emitter due to low HAP fuel materials can still be a best performer). In addition, the fact that a specific level of performance is unintended is not a legal basis for excluding the source's performance from consideration. *National Lime II*; 233 F.3d at 640.

The *Brick MACT* decision also stated that EPA may account for variability in setting floors. The DC Circuit Court found that "EPA may not use emission levels of the worst performers to estimate variability of the best

performers without a demonstrated relationship between the two." 479 F.3d at 882.

A second DC Circuit Court opinion is also relevant to this proposal. In *Sierra Club v. EPA*, 551 F.3d 1019 (DC Cir. 2008), the DC Circuit Court vacated the portion of the regulations contained in the General Provisions which exempt major sources from NESHAP during periods of startup, shutdown and malfunction (SSM). The regulations (in 40 CFR 63.6(f)(1) and 63.6(h)(1)) provided that sources need not comply with the relevant CAA section 112(d) standard during SSM events and instead must "minimize emissions * * * to the greatest extent which is consistent with safety and good air pollution control practices." As a result of the DC Circuit Court decision, sources must comply with the emission standards at all times and we are addressing SSM in this proposed rulemaking. Discussion of this issue may be found later in this preamble.

A third relevant DC Circuit Court opinion is *National Lime II* (233 F.3d 625), where, in considering whether EPA may use PM, a criteria pollutant, as a surrogate for metal HAP, the DC Circuit Court stated that EPA "may use a surrogate to regulate hazardous pollutants if it is reasonable' to do so" and laid out criteria establishing a three-part analysis for determining whether the use of PM as a surrogate for non-Hg metal HAP was reasonable. The DC Circuit Court found that PM is a reasonable surrogate for HAP if: (1) "HAP metals are invariably present in * * * PM;" (2) "PM control technology indiscriminately captures HAP metals along with other particulates;" and (3) "PM control is the only means by which facilities achieve' reductions in HAP metal emissions." 233 F.3d at 639. If these criteria are satisfied and the

PM emission standards reflect what the best sources achieve—complying with CAA section 7412(d)(3)—"EPA is under no obligation to achieve a particular numerical reduction in HAP metal emissions." We have considered this case in evaluating whether the surrogate standards we propose to establish in this proposed rule are reasonable.

E. EPA's Response to the Vacatur of the 2005 Action

After the vacatur of the Revision Rule, EPA evaluated the HAP and other emissions data available to establish CAA section 112(d) standards for coal- and oil-fired EGUs and determined that additional HAP emission data were required. EPA initiated an information collection effort entitled "Electric Utility Steam Generating Unit Hazardous Air Pollutant Emissions Information Collection Effort" (OMB Control Number 2060-0631). This information collection (2010 ICR) was conducted by EPA's Office of Air and Radiation (OAR) pursuant to CAA section 114 to assist the Administrator in developing emissions standards for coal- and oil-fired EGUs pursuant to CAA section 112(d). CAA section 114(a) states, in pertinent part:

For the purpose of * * * (iii) carrying out any provision of this Chapter * * * (1) the Administrator may require any person who owns or operates any emission source * * * to * * * (D) sample such emissions (in accordance with such procedures or methods, at such locations, at such intervals, during such periods and in such manner as the Administrator shall prescribe); (E) keep records on control equipment parameters, production variables or other indirect data when direct monitoring of emissions is

impractical * * *; (G) provide such other information as the Administrator may reasonably require * * *

Prior to issuance of the information collection effort, information necessary to identify all coal- and oil-fired EGUs as defined in CAA section 112(a)(8) was publicly available for EGUs owned and operated by publicly-owned utility companies, Federal power agencies, rural electric cooperatives, investor-owned utility generating companies, and nonutility generators (such units include, but may not be limited to, independent power producers (IPPs), qualifying facilities, and combined heat and power (CHP) units). The most recent information available was for 2005, and the available information generally did not include any information on permitted HAP emission limits; or monitoring, recordkeeping, and reporting requirements for HAP emissions; and we did not have complete HAP emissions data for any EGU. Additionally, we had little current information on the fuel amounts received, fuel sources, fuel shipment methods, or results of previously conducted fuel analyses for coal- and oil-fired EGUs, or for results from tests conducted since January 1, 2005. We did not have emissions test results that would provide data for emissions of a variety of pollutants, including: PM, PM with an aerodynamic diameter equal to or less than 2.5 micrometers (PM[2.5]); SO[2]; HCl/HF/HCN; metal HAP (including compounds of Sb, As, Be, Cd, Cr, Co, Pb, Mn, Ni, and Se); Hg; total organic hydrocarbons (THC); volatile organic compounds (VOC); and carbon monoxide (CO).

To obtain the information necessary to evaluate coal- and oil-fired EGUs, EPA developed a two-phase ICR and published the first notice in the Federal Register for comment consistent with the

requirements of the PRA. 74 FR 31725 (July 2, 2009). We received comments from industry and other interested parties. We also met with industry and other interested parties, and published a revised ICR in the Federal Register for another round of comments consistent with the PRA. 74 FR 58012 (November 10, 2009). OMB approved the ICR on December 24, 2009, and we sent the ICR to owners and operators of EGUs on December 31, 2010.

As stated above, the ICR contained two phases or components. The first component solicited information from all potentially affected units. EPA provided the survey in electronic format; however, written responses were also accepted. The survey was submitted to all coal- and oil-fired EGUs listed in the 2007 version of the DOE's Energy Information Administration's (EIA) Forms 860 and 923, "Annual Electric Generator Report," and "Power Plant Operations Report," respectively.

The second component required the owners/operators of a limited number of coal-and oil-fired EGUs to conduct stack testing in accordance with an EPA-approved protocol. Some coal-fired units were selected to be tested because we determined based on the information available that the units were among the top performing 15 percent of sources in the coal subcategory for certain types of HAP. Best-performing coal-fired units to be tested were selected to cover three groups of HAP that may be regulated through the use of surrogate standards: (1) Non-Hg metallic HAP (*e.g.*, As, Pb, Se); (2) acid gas HAP (*e.g.*, HCl, HF, HCN); (3) and non-dioxin/furan organic HAP. We also required the non-Hg metallic HAP sources to test for Hg even though Hg is to be regulated separately and not covered by any non-Hg metallic HAP surrogacy.

Fifty coal-fired units were also selected at random from the entire population of coal-fired EGUs to test for dioxin/furan organic HAP. An additional 50 coal-fired units were selected at random from among those units not selected as being "top performing" units to represent those coal-fired units not comprising the top-performing units in the three HAP surrogate groups; these 50 randomly selected units were required to test for all HAP except dioxin/furan organic HAP. Data from this last grouping was collected so we could estimate the HAP emission reductions associated with the proposed standards. Oil-fired units to be tested were also selected at random to test for HAP in all three groups of HAP noted above, in addition to testing for Hg and dioxin/furan.

The testing consisted of three runs at the sampling location and was in accordance with a specified emission test method. The owner/operator of each selected EGU was also required to collect and analyze, in accordance with an acceptable procedure, three fuel samples from the fuel fed to the EGU during each stack test. Additional details of the required sampling may be found in Docket entry EPA-HQ-OAR-2009-0234-0062.

In phase one, all coal- and oil-fired EGUs identified by EPA as being potentially subject sources under the definition in CAA section 112(a)(8), including all integrated gasification combined cycle (IGCC) EGUs and all EGUs fired by petroleum coke, were required to submit information to EPA. The sources were required to provide information on the current operational status of the unit, including applicable controls installed, along with emissions information from the preceding 5 years. This information was

necessary for EPA to fully characterize the category and update our database of coal- and oil-fired EGUs.

Phase two was the testing phase. As stated above, coal-fired units to be tested were selected to cover five HAP or groups of HAP, three of which may be regulated through the use of surrogate pollutant standards and were chosen because EPA determined the units were best performing units for one or more of the three HAP surrogate groups. In the stack testing, each facility was required to test after the last control device or at the stack if the stack is not shared with other units using different controls. In this way, the facility would test before any "dilution" by gases from a separately-controlled unit. Under certain circumstances, however, testing after a common control device or at the common stack was allowed.

EPA selected for testing the sources that the Agency believed, based on a variety of factors and information available to the Agency at the time, were the best performing sources for the three HAP surrogate groups for which they were required to test. In targeting the best performing sources, EPA required testing for approximately 15 percent of all coal-fired EGUs for the 3 HAP surrogate groups—non-Hg metal HAP and PM; non-dioxin/furan organic HAP, total hydrocarbon, CO, and VOC; and acid gas HAP and SO[2]. As we stated in response to comments on the proposed 2010 ICR, we targeted the best performing coal-fired sources for certain HAP groups because the statute requires the Agency to set the MACT floor at the "average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has information)" in the category. By targeting the best performing 15 percent of coal-fired EGUs for testing in the 3 HAP groups, we

concluded that we would have emissions data on the best performing 12 percent of all existing coal-fired EGUs. In this proposed rule, we used data from sources representing the best performing 12 percent of all sources in any category or subcategory to establish the CAA section 112(d) standards for the 3 HAP groups because we believe we have identified the best performing 12 percent of sources for those subcategories with 30 or more sources. For Hg from coal-fired units, we used the top 12 percent of the data obtained because, even though we required Hg testing for the units testing for the non-Hg metallic HAP, we did not believe those units represented the top performing 12 percent of sources for Hg in the category at the time we issued the ICR and we made no assertions to that effect. For oil-fired units, we also used the top 12 percent of the data obtained because we were unable, based on the information available, to determine the best performing oil-fired units. The primary reason for our inability to identify best performing oil-fired units is that such units are generally uncontrolled or controlled only with an ESP. The approach for both coal- and oil-fired EGUs was discussed with, and agreed upon by, several industry and environmental organization stakeholders prior to finalizing the ICR.

The acid-gas HAP, HCl and HF, are water-soluble compounds and are more soluble in water than is SO[2]. (Cyanide, representing the "cyanide compounds," and Cl[2] gas are also water-soluble and are considered "acid-gas HAP" in this proposal.) Hydrogen chloride also has a large acid dissociation constant (*i.e.*, HCl is a strong acid) and it, thus, will react easily in an acid-base reaction with caustic sorbents (*e.g.*, lime, limestone). The same is true for

HF. This indicates that both HCl and HF will be more rapidly and readily removed from a flue gas stream than will SO[2], even when only plain water is used. In FBC systems, the acid gases and SO[2] are adsorbed by the sorbent (usually limestone) that is added to the coal and an inert material (*e.g.*, sand, silica, alumina, or ash) as part of the FBC process.

Hydrogen chloride and HF have also been shown to be effectively removed using DSI where a dry, alkaline sorbent (*e.g.*, hydrated lime, trona, sodium carbonate) is injected upstream of a PM control device.

Chlorine in the fuel coal may also partition in small amounts to Cl[2]. This is normally a very small fraction relative to the formation of HCl. Limited testing has shown that Cl[2] gas is also effectively removed in FGD systems. Although Cl[2] is not strictly an acidic gas, it is grouped here with the "acid gas HAP" because it is controlled using the same technologies.

Because the technologies for removal of the acid gases are primarily those that are also used for FGD, we consider emissions of SO[2], a commonly measured pollutant, as a potential surrogate for emissions of the acid-gas HAP HCl, HF, HCN, and Cl[2]. Although use of SO[2] as a surrogate for acid gas HAP has not been used in any CAA section 112 rules by EPA, it has been used in a number of state permitting actions (See Docket entry EPA-HQ-OAR-2009-0234-0062). Hydrogen chloride has been used as a surrogate for the acid gas HAP in other Agency actions (*e.g.*, Portland Cement NESHAP, 75 FR 54970, September 9, 2010 (final rule); major and area source Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP (collectively, Boiler NESHAP), 75

FR 32005, June 4, 2010; 75 FR 31895, June 4, 2010 (proposed rules; the final rules were signed on February 21, 2011)), and we propose to use HCl as a surrogate for all the acid gas HAP, with an alternative equivalent standard using SO[2] as a surrogate. In addition, we gathered sufficient data on HCl, HF, and HCN[152] to establish individual emission limitations if warranted.

EPA identified the units with the newest FGD controls installed for testing of acid gas HAP based on our analysis that FGD controls are the best at reducing acid gas HAP emissions. EPA also believes that the units with the newest FGD systems represent those units having to comply with the most recent, and, therefore, likely most stringent, emission limits for SO[2]. We determined that efforts by units to comply with stringent SO[2] limits would also likely represent the top performers with regard to acid gas HAP emissions. Specifics of the required testing may be found in Docket entry EPA-HQ-OAR-2009-0234-0062.

Dioxin/furan emissions data were obtained in support of the 1998 Utility Report to Congress. However, approximately one-half of those data were listed as being below the minimum detection level (MDL) for the given test. Dioxin/furan emissions from coal-fired EGUs are generally considered to be low, presumably because of the insufficient amounts of available chlorine. As a result of previous work

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[152] Although the combination of extended sampling times and stack chemistry for many units in this source category rendered the test method for HCN unreliable, yielding suspect HCN results, we still consider SO[2] or HCl emissions to be adequate surrogates for HCN emissions.

conducted on municipal waste combustors (MWC), it has also been proposed that the formation of dioxins and furans in exhaust gases is inhibited by the presence of sulfur.[153] Further, it has been suggested that if the sulfur-to-chlorine ratio (S:Cl) in the flue gas is greater than 1.0, then formation of dioxins/furans is inhibited.[154] [155] The vast majority of the coal analyses provided through the 1999 ICR effort indicated S:Cl values greater than 1.0. As a result, EPA expected that additional data gathering efforts would continue the trend of data being at or below the MDL. Even so, EPA believed it necessary to collect some additional data so that the trend could be affirmed or rejected for EGUs. If the trend were rejected, then EPA would be able to establish an emission limit for dioxin/furan; however, if the trend were affirmed, then EPA would need to seek alternatives to an emissions limit, such as a work practice standard. The latter approach might become necessary because measurements made at or below MDL generally indicate the presence, but not the exact quantity, of a substance. In addition, measurements made at or below the MDL have an accuracy on the order of plus or minus 50 percent, whereas other environmental measurements used by EPA in other rulemakings exhibit accuracies of plus or minus up to

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[153] Gullett, BK, *et al*. Effect of Cofiring Coal on Formation of Polychlorinated Dibenzo- p -Dioxins and Dibenzofurans during Waste Combustion. *Environmental Science and Technology*. Vol. 34, No. 2:282-290. 2000.

[154] Raghunathan, K, and Gullett, BK. Role of Sulfur in Reducing PCDD and PCDF Formation. *Environmental Science and Technology*. Vol. 30, No. 6:1827-1834. 1996.

[155] Li., H, et al. Chlorinated Organic Compounds Evolved During the combustion of Blends of Refuse-derived Fuels and Coals. *Journal of Thermal Analysis*. Vol. 49:1417-1422. 1997.

15 percent. Sampling and analytical methods for dioxins/furans have improved since the 1990's work, so their MDLs are expected to have decreased. Moreover, for this sampling effort, we required sampling periods to be extended up to eight times longer than normal to collect more sample volume, thus, hopefully improving detection capability. Note that although longer sampling periods can be obtained during short term emissions testing, maintaining such longer sampling times becomes impractical, if not infeasible, for continuous monitoring.

For these reasons, we selected 50 units at random from the entire coal-fired EGU population to conduct emission testing for dioxins/furans. EPA has identified AC as a potential control technology for dioxin/furan control based on results of previous work done on MWC units, and several of the units that were selected for testing have ACI systems that had been installed for Hg control. Specifics of the required testing may be found in Docket entry EPA-HQ-OAR-2009-0234-0062.

Emissions of CO, VOC, and/or THC have, in the past, been used as surrogates for the non-dioxin/furan organic HAP based on the theory that efficient combustion leads to lower organic emissions (Portland Cement NESHAP—THC (75 FR 54970; September 9, 2010); Boiler NESHAP—CO (75 FR 32005, June 4, 2010; 75 FR 31895, June 4, 2010 (proposed rules; the final rules were signed on February 21, 2011)); Hazardous Waste Combustor NESHAP—CO (64 FR 52828; September 30, 1999)). Although indications are that organic HAP emissions are low (and perhaps below the MDL), there were very few emissions data available for these compounds from coal-fired EGUs and we determined that it was necessary to obtain additional information on which to establish

standards for these HAP. EPA identified the newest units as being representative of the most modern, and, thus, presumed most efficient units. The 170 newest units were selected and were required to test for CO, VOC, and THC; specifics of the required testing may be found in Docket entry EPA-HQ-OAR-2009-0234-0062.

Emissions of certain non-Hg metallic HAP (*i.e.*, Sb, Be, Cd, Cr, Co, Pb, Mn, and Ni) have been assumed to be well controlled by PM control devices. However, Hg and other non-Hg metallic HAP (*i.e.*, As and Se), have the potential to exist in both the particulate and vapor phases, and, therefore, may not be well controlled by PM control devices alone. Also, it has been shown through recent stack testing that certain of these HAP (*i.e.*, As and Se) may condense on (or as) very fine PM in the emissions from coal-fired units. There are very few recent emissions test data available showing the potential control of these metallic HAP from coal-fired EGUs.

EPA identified the units with the newest PM controls installed as the units to test for non-Hg metal HAP. EPA believed that these units represent those units having to comply with the most recent, and, therefore, likely most stringent, emission limits for PM. EPA believes units complying with stringent PM limits represent the top performers with regard to non-Hg metallic HAP emissions, even for those HAP that may at times form in other than the particulate phase. The units selected also included a number with ACI installed. The 170 units with the newest PM controls installed were selected and were required to test after that specific PM control (or at the stack if the PM control device is not shared with one or more other

units); specifics of the required testing may be found in Docket entry EPA-HQ-OAR-2009-0234-0062.

The capture of Hg is dependent on several factors including the chloride content of the coal, the sulfur content of the coal, the amount of unburned carbon present in the fly ash, and the flue gas temperature profile. All of these factors affect the chemical form (the speciation) of Hg in the flue gas. Mercury may exist as Hg<0>, as Hg<+2> (or reactive gaseous Hg, RGM) or as Hg[p]. Based on available data, EPA believes that sorbent injection (including ACI) has the potential to be a very effective technology for controlling Hg emissions in coal-fired plants, and some units using ACI for Hg control were among those selected for testing. EPA had no direct stack test results showing how effectively these ACI-equipped plants reduce their Hg emissions. The effectiveness of ACI is highly dependent upon the type of sorbent used (*i.e.*, chemically treated versus conventional AC) and on the amount injected. Further, previous data-gathering efforts had shown that FFs are capable of providing highly effective control of certain species of Hg and, in some cases, as high or higher than that achieved by ACI (ACI is not always used to achieve maximum reductions in Hg but, rather, to achieve permit requirements). Thus, testing for Hg was included with the testing for the non-Hg metallic HAP.

To be able to assess the impact of the standards (*e.g.*, reduction in HAP emissions over current conditions), EPA selected at random 50 units from the population of coal-fired units not selected in any of the above groups to test; specifics of the required testing may be found in Docket entry EPA-HQ-OAR-2009-0234-0062. We did not use the data gathered for the Utility Study because those data are outdated and lack sufficient

detail. Thus, EPA believed that gathering these data was necessary to assess the emissions of this important source category.

All IGCC units were also required to test; specifics of the required testing may be found in Docket entry EPA-HQ-OAR-2009-0234-0062.

EPA was able to identify the best performing coal-fired units for the three HAP surrogate groups but the data obtained in support of the Utility Study and the December 2000 Finding do not indicate that any oil-fired units control beyond some ESP use and the data do not show any correlation between the PM control at oil-fired units and emissions of non-Hg metallic HAP from those units. Further, no oil-fired EGU has been constructed in decades and no oil-fired EGU has a FGD system installed, eliminating the potential basis for the use of compliance with an SO [2] emissions limit that resulted in the installation of an FGD system as a basis for selecting best performers for the acid-gas HAP from such units. Thus, EPA had no basis for determining which oil-fired units may be the "best performers." Therefore, EPA required that 66 units selected at random from the population of known oil-fired units test their stack emissions; specifics of the required testing may be found in Docket entry EPA-HQ-OAR-2009-0234-0062.

All petroleum coke-fired units identified were required to test; specifics of the required testing may be found in Docket entry EPA-HQ-OAR-2009-0234-0062.

Pursuant to CAA section 112(q)(3), CAA section 112 as in effect prior to the 1990 CAA amendments remains in effect for radionuclide emissions from coal-

fired EGUs at the Administrator's discretion. For this reason, we did not require testing for radionuclides. We are also not proposing standards for radionuclides in this action.

F. What is the relationship between this proposed rule and other combustion rules?

1. CAA Section 111

Revised NSPS for SO[2], NO[X], and PM were promulgated under CAA section 111 for EGUs (40 CFR part 60, subpart Da) and industrial boilers (IB) (40 CFR part 60, subparts Db and Dc) on February 27, 2006 (71 FR 9866). As noted elsewhere, we are proposing certain amendments to 40 CFR part 60, subpart Da. In developing this proposed rule, we considered the monitoring requirements, testing requirements, and recordkeeping requirements of the existing NSPS to avoid duplicating requirements to the extent possible.

2. CAA Section 112

EPA has previously developed other non-EGU combustion-related NESHAP under CAA section 112(d) in addition to today's proposed rule for coal- and oil-fired EGUs. EPA signed final NESHAP for major and area source Boiler NESHAP on February 21, 2011 (to be codified at 40 CFR part 63, subpart DDDDD and subpart JJJJJJ, respectively) and promulgated standards for stationary combustion turbines (CT) on March 5, 2004 (69 FR 10512; 40 CFR part 63 subpart YYYY). In addition to these two NESHAP, on February 21, 2011, EPA also signed final CAA section

129 standards for commercial and institutional solid waste incinerator (CISWI) units, including energy recovery units (to be codified at 40 CFR part 60, subparts CCCC (NSPS) and DDDD (emission guidelines) and a definition of non-hazardous secondary materials that are solid waste (Non-hazardous Solid Waste Definition Rule, to be codified at 40 CFR part 241, subpart B). EGUs and IB that combust fossil fuel and solid waste, as that term is defined by the Administrator pursuant to the Resource Conservation and Recovery Act (RCRA), will be subject to section 129 (*e.g.*, CISWI energy recovery units), unless they meet one of the exemptions in CAA section 129(g). CAA section 129 standards are discussed in more detail below.

The two IB NESHAP, CT NESHAP, and this proposed rule will regulate HAP emissions from sources that combust fossil fuels for electrical power, process operations, or heating. The differences among these rules are due to the size of the units (MWe or Btu/hr), the boiler/furnace technology, or the portion of their electrical output (if any) for sale to any utility power distribution systems. *See* CAA section 112(a)(8) (defining EGU) earlier.

All of the MWe ratings quoted in the proposed rule are considered to be the original nameplate rated capacity of the unit. Cogeneration is defined as the simultaneous production of power (electricity) and another form of useful thermal energy (usually steam or hot water) from a single fuel-consuming process.

The CT rule regulates HAP emissions from all simple-cycle and combined-cycle stationary CTs producing electricity or steam for any purpose. Because of their combustion technology, simple-cycle

and combined-cycle stationary CTs (with the exception of IGCC units that burn gasified coal or petroleum coke syngas) are not considered EGUs for purposes of this proposed rule.

Any combustion unit, regardless of size, that produces steam to serve a generator that produces electricity exclusively for industrial, commercial, or institutional purposes (*i.e.*, no sales are made to the national electrical distribution grid) is considered an IB unit. A fossil fuel-fired combustion unit that serves a generator that produces electricity for sale is not considered to be an EGU under the proposed rule if the size of the combustion unit is less than or equal to 25 MWe. Units under that size would be subject to one of appropriate Boiler NESHAP. Further, EPA interprets the CAA section 112(a)(8) definition such that a non-cogeneration unit must both have a combustion unit of more than 25 MWe and supply more than 25 MWe to any utility power distribution system for sale to be considered an EGU pursuant to this proposed rule so as to be consistent with the cogeneration definition in CAA section 112(a)(8). Such units that sell less than 25 MWe of their power generation to the grid would be subject to the appropriate Boiler NESHAP.

As noted earlier, natural gas-fired EGU's were not included in the December 2000 listing. Thus, this proposed rule would not regulate a unit that otherwise meets the CAA section 112(a)(8) definition of an EGU but combusts natural gas exclusively or natural gas in combination with another fuel where the natural gas constitutes 90 percent or more of the average annual heat input during the previous 3 calendar years or 85.0 percent or more of the annual heat input during any one of those calendar years. Such units are

considered to be natural gas-fired EGUs and would not be subject to this proposed rule.

The CAA does not define the terms "fossil fuel" and "fossil fuel fired;" therefore, we are proposing definitions for both terms. The definition of "fossil fuel fired" will determine the applicability of the proposed rule to combustion units that sell electricity to the utility power distribution system. A number of units that may otherwise meet the CAA section 112(a)(8) EGU definition fire primarily non-fossil fuels (*e.g.*, biomass). However, these units generally startup using either natural gas or oil and may use these fuels (or coal) during normal operation for flame stabilization. We have included a definition that will establish the scope of applicability based in part on the amount of fossil fuel combustion necessary to make a unit become "fossil fuel fired," and the units that combust primarily non-fossil fuel will be subject to this proposed rule should they fire more than that amount of coal or oil. Specifically, EPA is proposing that an EGU must be capable of combusting more than 73 MWe (250 MMBtu/hr) heat input[156] (equivalent to 25 MWe output) of coal or oil to be considered an EGU subject to this proposed rule. To be "capable of combusting" coal or oil, a unit would need to have fossil fuels allowed in their permits and have the appropriate fuel handling facilities on-site (*e.g.*, coal handling equipment, including for purposes of example, but not limited to, coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities).

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[156] Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and IB).

In addition, EPA is proposing that an EGU must have fired coal or oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years to be considered a fossil fuel-fired EGU subject to this proposed rule. Units that do not meet these definitions would, in most cases, be considered IB units subject to one of the Boiler NESHAP. Thus, for example, a biomass-fired EGU, regardless of size, that utilizes fossil fuels for startup and flame stabilization purposes only (*i.e.*, less than or equal to 250 MMBtu/hr and used less than 10.0 percent of the average annual heat input during the previous 3 calendar years or less than 15.0 percent of the annual heat input during any one of those calendar years) is not considered to be a fossil fuel-fired EGU under this proposed rule. EPA has based its threshold value on the definition of "oil-fired" in the ARP found at 40 CFR 72.2. As EPA has no data on such use for (*e.g.*) biomass co-fired EGUs because their use has not yet become commonplace, we believe this definition also accounts for the use of fossil fuels for flame stabilization use without inappropriately subjecting such units to this proposed rule. EPA solicits comment on the use of these definitions. Commenters suggesting alternate definitions (including thresholds) should provide detailed information in support of their comment (*e.g.*, 3- to 5-year average fossil fuel use under conditions of startup and flame stabilization).

Also, a cogeneration facility that sells electricity to any utility power distribution system equal to more than one-third of their potential electric output capacity and more than 25 MWe is considered to be an EGU if it is fossil fuel fired as that term is defined

above. For such units, EPA is proposing that the unit must be capable of combusting sufficient coal or oil to generate 25 MWe from the fossil fuel alone, and must provide for sale to any utility power distribution system electricity equal to more than one-third of their potential electric output capacity and greater than 25 MWe electrical output. However, a cogeneration facility that meets the above definition of an EGU during any portion of a month would be subject to the proposed EGU rule for the succeeding 6 calendar months (combustion units that begin combusting solid waste must immediately comply with an applicable CAA section 129 standard (*e.g.*, CISWI standards applicable to energy recovery units)).

We recognize that different section 112 rules may impact a particular unit at different times. For example there will likely be some cogeneration units that are determined to be covered under the Boiler NESHAP. Such unit may make a decision to increase/decrease the proportion of production output being supplied to the electric utility grid, thus causing the unit to meet the EGU cogeneration criteria (*i.e.*, greater than one-third of its potential output capacity and greater than 25 MWe). A unit subject to one of the Boiler NESHAP that increases its electricity output and meets the definition of an EGU would be subject to the proposed EGU NESHAP for the 6-month period after the unit meets the EGU definition. Assuming the unit did not meet the definition of an EGU following that initial occurrence, at the end of the 6-month period it would revert back to being subject to the Boiler NESHAP. This approach is consistent with that taken on the CISWI rulemaking.

EPA solicits comment on the extent to which this situation might occur and whether the 6-month period

is appropriate. Given the differences between the rules, should EPA address reclassification of the sources between the rules, particularly with regard to initial and ongoing compliance requirements and schedules? (As noted above, EPA is proposing to consider as an EGU any cogeneration unit that meets the definition noted earlier during any month in a year.) We specifically solicit comments as to how to address sources that may meet the definition of an EGU for only parts of a year. We also solicit comment on whether we should include provisions similar to those included in the final CISWI rule to address units that combust different fuels at different times. See Final CISWI Rule, 40 CFR 60.2145, http://www.epa.gov/airquality/combustion/docs/20110221ciswi.pdf.

Another situation may occur where one or more coal- or oil-fired EGU(s) share an air pollution control device (APCD) and/or an exhaust stack with one or more similarly-fueled IB unit(s). To demonstrate compliance with two different rules, the emissions have to either be apportioned to the appropriate source or the more stringent emission limit must be met. Data needed to apportion emissions are not currently required by this proposed rule or the final Boiler NESHAP. Therefore, EPA is proposing that compliance with the more stringent emission limit be demonstrated.

EPA solicits comment on the extent to which this situation might occur. Given potential differences between the rules, how should EPA address apportionment of the emissions to the individual sources with regard to initial and ongoing compliance requirements? EPA specifically requests comment on the appropriateness of a mass balance-type

methodology to determine pollutant apportionment between sources both pre-APCD and post-APCD.

3. CAA Section 129

Units that combust "non-hazardous solid waste" as defined by the Administrator under RCRA are regulated under the provisions of CAA section 129. On February 21, 2011, EPA signed the final Non-Hazardous Solid Waste Definition Rule. Any EGU that combusts any solid waste as defined in that final rule is a solid waste incineration unit subject to CAA section 129.

In the Non-Hazardous Solid Waste Definition Rule, EPA determined that coal refuse from current mining operations is not considered to be a "solid waste" if it is not discarded. Coal refuse that is in legacy coal refuse piles is considered a "solid waste" because it has been discarded. However, if the discarded coal refuse is processed in the same manner as currently mined coal refuse, the coal refuse would not be a solid waste and, therefore, the combustion of such material would not subject the unit to regulation under CAA section 129. By contrast, the unit would be subject to this rule if it meets the definition of EGU. If the unit combusts solid waste, it would be subject to emission standards under CAA section 129. *See*, *e.g.*, CISWI rule. Coal refuse properly processed is a product fossil fuel (*i.e.*, not a solid waste) if it is not a solid waste; thus, combustion units that otherwise meet the CAA section 112(a)(8) EGU definition that combust coal refuse that is product fuel not a solid waste are EGUs subject to this proposed rule. For this proposed rule, we assumed that all units that combust coal refuse and otherwise meet the definition of a coal-fired EGU combust newly mined coal refuse or coal refuse from legacy piles that

has been processed such that it is not a solid waste. We request comment on this assumption and whether there are any units combusting coal refuse that is a solid waste such that the units would be solid waste incineration units instead of EGUs.

Further, CAA section 129(g)(1)(B) exempts from regulation under CAA section 129

"* * * qualifying small power production facilities, as defined in section 796(17)(C) of Title 16, or qualifying cogeneration facilities, as defined in section 796(18)(B) of Title 16, which burn homogeneous waste * * * for the production of electric energy or in the case of qualifying cogeneration facilities which burn homogeneous waste for the production of electric energy and steam or other forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes * * *"

Thus, qualifying small power production facilities and cogeneration facilities that burn a homogeneous waste would be exempt from regulation under CAA section 129. If the "homogeneous waste" material combusted is a fossil fuel, then the units that are exempt from regulation under CAA section 129 and that otherwise meet the definition of an EGU under CAA section 112(a)(8) would be covered under this proposed rule. For example, a unit that combusts only coal refuse that is a solid waste would be subject to this proposed rule if the unit met the definition of EGU and the coal refuse was determined to be a "homogenous waste" as that term is defined in the final CAA section 129 CISWI standards (the final rule was signed on February 21, 2011, but has not yet been published in the Federal Register).

G. What emission limitations and work practice standards must I meet?

We are proposing the emission limitations presented in Tables 10 and 11 of this preamble. Within the two major subcategories of "coal" and "oil," emission limitations were developed for new and existing sources for five subcategories, two for coal-fired EGUs, one for coal- and solid oil-derived IGCC EGUs, and two for oil-fired EGUs, which we developed based on unit type.

We are proposing that new or existing EGUs are "coal-fired" if they combust coal and meet the proposed definition of "fossil fuel fired." We are proposing that an EGU is considered to be a "coal-fired unit designed for coal greater than or equal to 8,300 Btu/lb" if the EGU: (1) Combusts coal; (2) meets the proposed definition of "fossil fuel fired;" and (3) burns any coal in an EGU designed to burn a coal having a calorific value (moist, mineral matter-free basis) of greater than or equal to 19,305 kilojoules per kilogram (kJ/kg) (8,300 British thermal units per pound (Btu/lb)) in an EGU with a height-to-depth ratio of less than 3.82. We are proposing that the EGU is considered to be a "coal-fired unit designed for coal less than 8,300 Btu/lb" if the EGU: (1) Combusts coal; (2) meets the proposed definition of "fossil fuel fired;" and (3) burns any virgin coal in an EGU designed to burn a nonagglomerating fuel having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) in an EGU with a height-to-depth ratio of 3.82 or greater.

We are proposing that the EGU is considered to be an IGCC unit if the EGU: (1) Combusts gasified coal or solid oil-derived (*e.g.*, petroleum coke); (2) meets the proposed definition of "fossil fuel fired;" and (3) is

classified as an IGCC unit. We are not proposing to subcategorize IGCC EGUs based on the source of the syngas used (*i.e.*, coal, petroleum coke). Based on information available to the Agency, although the fuel characteristics of coal and petcoke are quite different, the syngas products are very similar from both feedstocks.[157]

We are proposing that the EGU is considered to be "liquid oil" fired if the EGU burns liquid oil and meets the proposed definition of "fossil fuel fired." We are proposing that the EGU is considered to be "solid oil-derived fuel-fired" if the EGU burns any solid oil-derived fuel (*e.g.*, petroleum coke) and meets the proposed definition of "fossil fuel fired." EPA is also considering a limited-use subcategory to account for liquid oil-fired units that only operate a limited amount of time per year on oil and are inoperative the remainder of the year. Such units could have specific emission limitations, reduced monitoring requirements (limited operation may preclude the ability to conduct stack testing), or be held to the same emission limitations (which could be met through fuel sampling) as other liquid oil-fired units. EPA solicits comment on all of these proposed subcategorization approaches.

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[157] U.S. Department of Energy, Wabash River Coal Gasification Repowering Project. Project Performance Summary; Clean Coal Technology Demonstration Program. DOE/FE-0448. July 2002.

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Supreme Court, U.S.
FILED
JUL 14 2014

No. 14-___

IN THE

Supreme Court of the United States

NATIONAL MINING ASSOCIATION, PETITIONER

v.

ENVIRONMENTAL PROTECTION AGENCY, RESPONDENT

ON PETITION FOR WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

PETITION FOR A WRIT OF CERTIORARI
VOLUME 4 of 4

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Table 10—Emission Limitations for Coal-Fired and Solid Oil-Derived Fuel-Fired EGUS

Subcategory	Total particulate matter	Hydrogen chloride	Mercury
Existing coal-fired unit designed for coal >/= 8,300 Btu/lb	0.030 lb/MMBtu (0.30 lb/MWh)	0.0020 lb/MMBtu (0.020 lb/MWh)	1.0 lb/TBtu (0.0.008 lb/GWh).
Existing coal-fired unit designed for coal < 8,300 Btu/lb	0.030 lb/MMBtu (0.30 lb/MWh)	0.0020 lb/MMBtu (0.020 lb/MWh)	11.0 lb/TBtu (0.20 lb/GWh) 4.0 lb/TBtu * (0.040 lb/GWh *).
Existing—IGCC	0.050 lb/MMBtu (0.30 lb/MWh)	0.00050 lb/MMBtu (0.0030 lb/MWh)	3.0 lb/TBtu (0.020 lb/GWh).
Existing—Solid oil-derived	0.20 lb/MMBtu (2.0 lb/MWh)	0.0050 lb/MMBtu (0.080 lb/MWh)	0.20 lb/TBtu (0.0020 lb/GWh).
New coal-fired unit designed for coal >/= 8,300 Btu/lb	0.050 lb/MWh	0.30 lb/GWh	0.000010 lb/GWh.
New coal-fired unit designed for coal < 8,300 Btu/lb	0.050 lb/MWh	0.30 lb/GWh	0.040 lb/GWh.

Table 10—Emission Limitations for Coal-Fired and Solid Oil-Derived Fuel-Fired EGUS

Subcategory	Total particulate matter	Hydrogen chloride	Mercury
New—IGCC	0.050 lb/MWh *	0.30 lb/GWh *	0.000010 lb/GWh *.
New—Solid oil-derived	0.050 lb/MWh	0.00030 lb/MWh	0.0020 lb/GWh.

Note: lb/MMBtu = pounds pollutant per million British thermal units fuel input.

lb/TBtu = pounds pollutant per trillion British thermal units fuel input.

lb/MWh = pounds pollutant per megawatt-electric output (gross).

lb/GWh = pounds pollutant per gigawatt-electric output (gross).

* Beyond-the-floor limit as discussed elsewhere.

Table 11—Emission Limitations for Liquid Oil-Fired EGUS

Subcategory	Total HAP metals *	Hydrogen chloride	Hydrogen fluoride
Existing—Liquid oil	0.000030 lb/MMBtu (0.00030 lb/MWh)	0.00030 lb/MMBtu (0.0030 lb/MWh)	0.00020 lb/MMBtu. (0.0020 lb/MWh).
New—Liquid oil	0.00040 lb/MWh	0.00050 lb/MWh	0.00050 lb/MWh.

* Includes Hg.

Pursuant to CAA section 112(h), we are proposing a work practice standard for organic HAP, including emissions of dioxins and furans, from all subcategories of EGU. The work practice standard being proposed for these EGUs would require the implementation of an annual performance (compliance) test program as

described elsewhere in this preamble. We are proposing work practice standards because the data confirm that the significant majority of the measured organic HAP emissions from EGUs are below the detection levels of the EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units. As discussed later in this preamble, EPA believes the inaccuracy of a majority of measurements coupled with the extended sampling times used, fulfill the criteria for these HAP to be subject to a work practice standard under CAA section 112(h).

We are proposing a beyond-the-floor standard for Hg only for all existing coal-fired units designed for coal less than 8,300 Btu/lb based on the use of ACI for Hg control, as described elsewhere in this preamble. We are proposing a beyond-the-floor standard for all pollutants for new IGCC units based on the new-source limits for coal-fired units designed for coal greater than or equal to 8,300 Btu/lb as described elsewhere in this preamble.

As noted elsewhere in this preamble, we are proposing to use total PM as a surrogate for the non-Hg metallic HAP and HCl as a surrogate for the acid gas HAP for all subcategories of coal-fired EGUs and for the solid oil derived fuel-fired EGUs. For liquid oil-fired EGUs, we are proposing total HAP metal, HCl, and HF emission limitations.

In addition, we are proposing three alternative standards for certain subcategories: (1) SO[2] (as an alternative equivalent to HCl for all subcategories with add-on FGD systems); (2) individual non-Hg metallic HAP (as an alternate to PM for all subcategories except liquid oil-fired); (3) total non-Hg metallic HAP (as an alternate to PM for all

subcategories except liquid oil-fired); and (4) individual metallic HAP (as an alternate to total metal HAP) for the liquid oil-fired subcategory. These alternative proposed standards are discussed elsewhere in this preamble.

H. What are the startup, shutdown, and malfunction (SSM) requirements?

The DC Circuit Court vacated portions of two provisions in EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. S *ierra Club v. EPA, 551 F.3d 1019 (DC Cir. 2008),* cert. denied, *130 S. Ct. 1735 (U.S. 2010).* Specifically, the DC Circuit Court vacated the SSM exemption contained in *40 CFR 63.6(f)(1)* and *40 CFR 63.6(h)(1),* that are part of a regulation, commonly referred to as the "General Provisions Rule," that EPA promulgated under CAA section 112. When incorporated into CAA section 112(d) regulations for specific source categories, these two provisions exempt sources from the requirement to comply with the otherwise applicable CAA section 112(d) emission standard during periods of SSM.

Consistent with *Sierra Club,* EPA is proposing standards in this rule that apply at all times. In proposing the standards in this rule, EPA has taken into account startup and shutdown periods and, for the reasons explained below, has not proposed different standards for those periods. The standards that we are proposing are 30 boiler operating day averages. EGUs, especially solid fuel-fired EGUs, do not normally startup and shutdown frequently and typically use cleaner fuels (*e.g.,* natural gas or oil) during the startup period. Based on the data before the Agency, we are not establishing different emissions standards for startup and shutdown.

To appropriately determine emissions during start-up and shutdown and account for those emissions in assessing compliance with the proposed emission standards, we propose use of a default diluent value of 10.0 percent O[2] or the corresponding fuel specific CO[2] concentration for calculating emissions in units of lb/MMBtu or lb/TBtu during startup or shutdown periods. For calculating emissions in units of lb/MWh or lb/GWh, we propose source owners use an electrical production rate of 5 percent of rated capacity during periods of startup or shutdown. We recognize that there are other approaches for determining emissions during periods of startup and shutdown, and we request comment on those approaches. We further solicit comment on the proposed approach described above and whether the values we are proposing are appropriate.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *." *40 CFR 63.2.* EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times. In *Mossville Environmental Action Now v. EPA, 370 F.3d 1232, 1242 (DC Cir. 2004),* the DC Circuit Court upheld as reasonable standards that had factored in variability of emissions under all operating conditions. However, nothing in CAA section 112(d) or in case law requires that EPA anticipate and account for the innumerable types of

potential malfunction events in setting emission standards. *See, Weyerhaeuser v. Costle*, 590 F.2d 1011, 1058 (DC Cir. 1978) ("In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.")

Further, it is reasonable to interpret CAA section 112(d) as not requiring EPA to account for malfunctions in setting emissions standards. For example, we note that CAA section 112 uses the concept of "best performing" sources in defining MACT, the level of stringency that major source standards must meet. Applying the concept of "best performing" to a source that is malfunctioning presents significant difficulties. The goal of best performing sources is to operate in such a way as to avoid malfunctions of their units.

Moreover, even if malfunctions were considered a distinct operating mode, we believe it would be impracticable to take malfunctions into account in setting CAA section 112(d) standards for EGUs. As noted above, by definition, malfunctions are sudden and unexpected events and it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources in the category. Moreover, malfunctions can vary in frequency, degree, and duration, further complicating standard setting.

In the unlikely event that a source fails to comply with the applicable CAA section 112(d) standards as a

result of a malfunction event, EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to reduce the likelihood that malfunctions would occur, minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or careless operation." *See 40 CFR 63.2* (definition of malfunction).

Finally, EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g.*, State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (September 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (February 15, 1983)). EPA is, therefore, proposing an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. *See* 40 CFR 63.10042 (defining "affirmative defense" to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also are proposing other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in section 63.10001. *See 40 CFR 22.24*. The

criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in *40 CFR 63.2* (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and/or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions "[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *." The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with 40 CFR 63.10000(b) and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that "[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *" and that "[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *" In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with CAA section 113. *See* also 40 CFR part 22.77.

I. What are the testing requirements?

We are proposing that the owner or operator of a new or existing coal- or oil-fired EGU must conduct performance tests to demonstrate compliance with all applicable emission limits. For units using certified continuous emissions monitoring systems (CEMS)

that directly measure the concentration of a regulated pollutant under proposed 40 CFR part 63, subpart UUUUU (*e.g.*, Hg CEMS, SO[2] CEMS, or HCl CEMS) or sorbent trap monitoring systems, the initial performance test would consist of all valid data recorded with the certified monitoring system in the first 30 operating days after the compliance date. For units using CEMS to measure a surrogate for a regulated pollutant (*i.e.*, PM CEMS), initial stack testing of the surrogate and the regulated pollutant conducted during the same compliance test period and under the same process (*e.g.*, fuel) and control device operating conditions would be required, and an operating limit would be established. Affected units would be required to conduct the following compliance tests where applicable:

(1) For coal-fired units, IGCC units, and solid oil-derived fuel-fired units, if you elect to comply with the total PM emission limit, then you would conduct HAP metals and PM emissions testing during the same compliance test period and under the same process (*e.g.*, fuel) and control device operating conditions initially and every 5 years using EPA Methods 29, 5, and 202. Continuous compliance would be determined using a PM CEMS with an operating limit established based on the filterable PM values measured using Method 5. If you elect to comply with the total HAP metals emission limit or the individual HAP metals emissions limits, then you would conduct total PM and HAP metals testing during the same compliance test period and under the same process (*e.g.*, fuel) and control device operating conditions at least once every 5 years and, to demonstrate continuous compliance, you would conduct total or individual HAP metals emissions testing every 2 months (or every month if you have no PM control device) using EPA Method 29.

Note that the filter temperature for each Method 29 or 5 emissions test is to be maintained at 160 +/- 14 [degrees] C (320 +/- 25 [degrees] F) and that the material in Method 29 impingers is to be analyzed for metals content.

(2) Coal-fired, IGCC, and solid oil-derived fuel-fired units would be required to use a Hg CEMS or sorbent trap monitoring system for continuous compliance using the continuous Hg monitoring provisions of proposed Appendix A to proposed 40 CFR part 63, subpart UUUUU. The initial performance test would consist of all valid data recorded with the certified Hg monitoring system in the first 30 boiler operating days after the compliance date.

(3) For coal-fired and solid oil-derived fuel-fired units and new or reconstructed IGCC units that have SO[2] emission controls and elect to use SO[2] CEMS for continuous compliance, an initial stack test for SO[2] would not be required. Instead the first 30 days of SO[2] CEMS data would be used to determine initial compliance. For units with or without SO[2] or HCl emission controls that elect to use HCl CEMS, an initial stack test for HCl would not be required. Instead the first 30 days of HCl CEMS data would be used to determine initial compliance. For units without HCl CEMS and without SO[2] or HCl emissions control devices, you would be required to conduct HCl emissions testing every month using EPA Method 26 if no entrained water droplets exist in the exhaust gas or Method 26A if entrained water droplets exist in the exhaust gas. For units without SO[2] or HCl CEMS but with SO[2] emissions control devices, you would conduct HCl testing at least every 2 months using EPA Method 26 or 26A. For units without SO[2] or HCl CEMS and without SO[2] emissions control

devices, you would conduct HCl emissions testing every month using EPA Method 26A if entrained water droplets exist in the exhaust gas or Method 26A or 26 if no entrained water droplets exist in the exhaust gas.

(4) For all required performance stack tests, you would conduct concurrent oxygen (O[2]) or carbon dioxide (CO[2]) emission testing using EPA Method 3A and then, use an appropriate equation, selected from among Equations 19-1 through 19-9 in EPA Method 19 to convert measured pollutant concentrations to lb/MMBtu values. Multiply the lb/MMBtu value by one million to get the lb/TBtu value (if applicable).

(5) For liquid oil-fired units, initial performance testing would be conducted as follows. For non-Hg HAP metals, use EPA Method 29. For Hg, conduct emissions testing using EPA Method 29 or Method 30B. For acid gases, conduct HCl and HF testing using EPA Methods 26A or 26. Conduct additional performance testing for Hg at least annually; conduct additional performance tests for HAP metals and acid gases every 2 months if the EGU has emission controls for metals or acid gases, and every month if the EGU does not have these controls.

(6) For existing units that qualify as low emitting EGUs (LEEs), conduct subsequent performance tests for the LEE qualified pollutants every 5 years and perform fuel analysis monthly.

Except for liquid oil-fired units, those EGUs with PM emissions control devices, without HCl CEMS but with HCl control devices, or for LEE, we are proposing that you monitor during initial performance testing specified operating parameters that you would use to demonstrate ongoing compliance. You would calculate

the minimum (or maximum, depending on the parameter measured) hourly parameter values measured during each run of a 3-run performance test. The average of the three minimum (or maximum) values from the three runs for each applicable parameter would establish a site-specific operating limit. The applicable operating parameters for which operating limits would be required to be established are based on the emissions limits applicable to your unit as well as the types of add-on controls on the unit. The following is a summary of the operating limits that we are proposing to be established for the various types of the following units:

(1) For units without wet or dry FGD scrubbers that must comply with an HCl emission limit, you must measure the average chlorine content level in the input fuel(s) during the HCl performance test. This is your maximum chlorine input operating limit.

(2) For units with wet FGD scrubbers, you must measure pressure drop and liquid flow rate of the scrubber during the performance test, and determine the maximum value for each test run. The average of the minimum hourly value for the three test runs establishes your minimum site-specific pressure drop and liquid flow rate operating levels. If different average parameter levels are measured during the Hg and HCl tests, the highest of the average values becomes your site-specific operating limit. If you are complying with an HCl emission limit, you must measure pH of the scrubber effluent during the performance test for HCl and determine the minimum hourly value for each test run. The average of the three minimum hourly values from the three test runs establishes your minimum pH operating limit.

(3) For units with dry scrubbers or DSI (including ACI), you would be required to measure the sorbent injection rate for each sorbent used during the performance tests for HCl and Hg and determine the minimum hourly rate of injected sorbent for each test run. The average of the three test run minimum values established during the performance tests would be your site-specific minimum sorbent injection rate operating limit. If different sorbents and/or injection rates are used during the Hg and HCl performance testing, the highest value for each sorbent becomes your site-specific operating limit for the respective HAP. If the same sorbent is used during the Hg and HCl performance testing, but at different injection rates, the highest average value for each sorbent becomes your site-specific operating limit. The type of sorbent used (*e.g.*, conventional AC, brominated AC, trona, hydrated lime, sodium carbonate, etc.) must be specified.

(4) For units with FFs in combination with wet scrubbers, you must measure the pH, pressure drop, and liquid flow rate of the wet scrubber during the performance test and calculate the minimum hourly value for each test run. The average of the minimum hourly values from the three test runs establishes your site-specific pH, pressure drop, and liquid flow rate operating limits for the wet scrubber.

(5) For units with an ESP in combination with wet scrubbers, you must measure the pH, pressure drop, and liquid flow rate of the wet scrubber during the HCl performance test and you must measure the voltage and current of each ESP collection field during the Hg and PM performance test. You would then be required to calculate the minimum hourly value of these parameters for each of the three test runs. The

average of the three minimum hourly values would establish your site-specific minimum pH, pressure drop, and liquid flow rate operating limit for the wet scrubber and the minimum voltage and current operating limits for the ESP.

(6) For liquid oil-fired or LEEs, you would be required to measure the Hg, Cl, and HAP metal content of the inlet fuel that was burned during the Hg, HCl and HF, and HAP metal emissions performance testing. The fuel content value for each of these compounds is your maximum fuel inlet operating limit for each of these compounds.

(7) For units with FFs, you must measure the output of the bag leak detection system (BLDS) sensor (whether in terms of relative or absolute PM loading) during each Hg, PM, and metals performance test. You would then be required to calculate the minimum hourly value of this output for each test run. The average of the minimum hourly BLDS values would establish your site-specific maximum BLDS sensor output and current operating limit for the BLDS.

(8) For units with an ESP, you must measure the voltage and current of each ESP collection field during each Hg, PM, and metals performance test. You would then be required to calculate the minimum hourly value of these parameters for each test run. The average of the three minimum hourly values would establish your site-specific minimum voltage and current operating limits for the ESP.

(9) Note that you establish the minimum (or maximum) hourly average operating limits based on measurements done during performance testing; should you desire to have differing operating limits which correspond to other loads, you should conduct

testing at those other loads to determine those other operating limits.

Instead of operating limits for dioxins and furans and non-dioxin/furan organic HAP, we are proposing that owners or operators of units submit documentation that a "tune up" meeting the requirements of the proposed rule was conducted. Such a "tune-up" would require the owner or operator of a unit to:

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, but you must inspect each burner at least once every 18 months);

(2) Inspect the flame pattern, as applicable, and make any adjustments to the burner necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(3) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly;

(4) Optimize total emissions of CO and NO[X]. This optimization should be consistent with the manufacturer's specifications, if available;

(5) Measure the concentration in the effluent stream of CO and NO[X] in ppm, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made); and

(6) Maintain on-site and submit, if requested by the Administrator, an annual report containing:

(i) The concentrations of CO and NO[X] in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after the adjustments of the EGU;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type and amount of fuel used over the 12 months prior to the adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period.

Many, if not most, EGUs have planned annual outages, and the inspection and tune up procedure was designed to occur during this normal occurrence. Nonetheless, we are proposing a maximum period of up to 18 months between inspections and tune ups to account for those EGUs with unusual planned outage schedules. We seek comment on the appropriateness of this period.

J. What are the continuous compliance requirements?

1. Continuous Compliance Requirements

To demonstrate continuous compliance with the emission limitations, we are proposing the following requirements:

(1) For IGCC units or units combusting coal or solid oil-derived fuel and electing to use PM as a surrogate for non-Hg HAP metals, you would install, certify, and operate PM CEMS in accordance with Performance Specification (PS) 11 in Appendix B to 40 CFR part 60, and to perform periodic, on-going quality assurance (QA) testing of the CEMS according to QA Procedure 2 in Appendix F to 40 CFR part 60. An operating limit (PM concentration) would be set during performance testing for initial compliance; the hourly average PM

concentrations would be averaged on a rolling 30 boiler operating day basis. Each 30 boiler operating day average would have to meet the PM operating limit.

IGCC units or units combusting coal or solid oil-derived fuel and electing to comply with the total non-Hg HAP metals emissions limit, would demonstrate continuous compliance by conducting Method 29 testing every two months if PM controls are installed or every month if no PM controls are installed. As an option, PM CEMS could be used to demonstrate continuous compliance as described above. IGCC units or units combusting coal or solid oil-derived fuel and electing to comply with the individual non-Hg HAP metals emissions limits, would have the option to demonstrate continuous compliance only by conducting Method 29; again, testing would be conducted every two months if PM controls are installed or every month if no PM controls are installed. IGCC units or units combusting coal or solid oil-derived fuel with PM controls but not using PM CEMS to demonstrate continuous compliance would also be required to conduct parameter monitoring and meet operating limits established during performance testing. Units using FFs would be required to install and operate BLDS. As mentioned earlier, the BLDS output would be required to be less than or equivalent with the average BLDS output determined during performance testing. Moreover, a source owner or operator would be required to operate the FFs such that the sum duration of alarms from the BLDS would not exceed 5 percent of the process operating time during any 6-month period. Units using an ESP would be required to install and operate sensors to detect and measure current and voltage for each field in the ESP. As mentioned earlier, the current and voltage values for

each field in the ESP would need to be greater than or equivalent with the maximum test run averages determined during performance testing.

(2) For IGCC units or units combusting coal or solid oil-derived fuel, we are proposing that Hg CEMS or sorbent trap monitoring systems be installed, certified, maintained, operated, and quality-assured in accordance with proposed Appendix A to 40 CFR part 63, subpart UUUUU, and that Hg levels (averaged on a rolling 30 boiler operating day basis) be maintained at or below the applicable Hg emissions limit. Given that the proposed Appendix A QA procedures for Hg CEMS are based on a Hg emissions trading rule (CAMR), and this proposal is for a not-to-exceed NESHAP, EPA solicits comments on whether these Hg CEMS QA procedures should be adjusted. Further, we are proposing that each pair of sorbent traps be used to collect Hg samples for no more than 14 operating days, and that the traps be replaced in a timely manner to ensure that Hg emissions are sampled continuously. In requiring continuous Hg monitoring, we assumed that most, if not all, of the units that were subject to CAMR purchased Hg CEMS and/or sorbent trap systems prior to the rule vacatur, and that many of these monitoring systems are currently installed and in operation. The Agency's conclusion regarding Hg CEMS purchases and installation is based in part on the significant number of units (over 100) that voluntarily opted to submit Hg CEMS data for the 2010 ICR. We also considered the steps taken by the industry to prepare for CAMR, and the fact that many state regulations currently require the installation and operation of Hg CEMS in order to demonstrate compliance with various SIP and consent decrees.

(3) For new or reconstructed IGCC units or coal-fired or solid oil-derived fuel-fired units with SO[2] emissions control devices, we are proposing two compliance options for acid gases. First, an SO[2] or an HCl CEMS could be installed and certified. We are proposing that the SO[2] monitor be certified and quality-assured according to 40 CFR part 75 or PS 2 or 6 and Procedure 1 in Appendices B and F, respectively, of 40 CFR part 60. We believe this is reasonable, because nearly all utility units are subject to the ARP, and coal-fired ARP units already have certified SO[2] monitors in place that meet Part 75 requirements. For HCl monitors, PS 15 or 6 in Appendix B to 40 CFR part 60 would be used for certification and, tentatively, Procedure 1 of Appendix F to 40 CFR part 60 would be followed for on-going QA.

Note that a PS specific to HCl CEMS has not been promulgated yet, but we expect to publish one prior to the compliance date of this proposed rule and to make it available to source owners and operators. In the meantime, the FTIR CEMS (PS 15) may be an appropriate choice for measuring continuous HCl concentrations. Hourly data from the SO[2] or HCl monitor would be converted to the units of the emission standard and averaged on a rolling 30 boiler operating day basis. Each 30 boiler operating day average would have to meet the applicable SO[2] or HCl limit.

The second option that we are proposing would be for units without SO[2] or HCl CEMS but with SO[2] emissions control devices. For these units, parameter operating limits, established during performance testing, would be monitored continuously, along with the already-mentioned frequent (every 2 months) HCl emissions testing. For units with wet FGD scrubbers,

we are proposing that you monitor pressure drop and liquid flow rate of the scrubber continuously and maintain 12-hour block averages at or above the operating limits established during the performance test. You must monitor the pH of the scrubber and maintain the 12-hour block average at or above the operating limit established during the performance test to demonstrate continuous compliance with the HCl emission limits.

For units with dry scrubbers or DSI systems, we are proposing that you continuously monitor the sorbent injection rate and maintain it at or above the operating limits established during the performance tests.

(4) For liquid oil-fired units, we are proposing to require testing as follows. HAP metals testing would be performed every other month if a unit has a non-Hg HAP metals control device, and every month if the unit does not have a non-Hg metals control device. We propose to require HCl and HF testing every other month if a unit has HCl and HF control devices, and monthly if the unit does not have these emissions controls.

(5) For each unit using PM, HCl, SO[2], or Hg CEMS for continuous compliance, we are proposing that you install, certify, maintain, operate and quality-assure the additional CEMS (*e.g.*, CEMS that measure oxygen or CO[2] concentration, stack gas flow rate, and moisture content) needed to convert pollutant concentrations to units of the emission standards or operating limits. Where appropriate, we have proposed that these additional CEMS may be certified and quality-assured according to 40 CFR part 75. Once again, we believe this is reasonable because almost all coal-fired utility units already have these monitors in place, under the ARP.

(6) For limited-use liquid oil combustion units, we are proposing that those units be allowed to demonstrate compliance with the Hg emission limit, the HAP metals, or the HCl and HF emissions limits separately or in combination based on fuel analysis rather than performance stack testing, upon request by you and approval by the Administrator. Such a request would require the owner/operator to follow the requirements in *40 CFR 63.8(f)*, which presents the procedure for submitting a request to the Administrator to use alternative monitoring, and, among other things, explain why a unit should be considered for eligibility, including, but not limited to, use over the previous 5 years and projected use over the next 5 years. Approval from the Administrator would be required before you could use this alternative monitoring procedure. If approval were granted by the Administrator, we are proposing that you would maintain fuel records that demonstrate that you burned no new fuels or fuels from a new supplier such that the Hg, the non-Hg HAP metal, the fluorine, or the chlorine content of the inlet fuel was maintained at or below your maximum fuel Hg, non-Hg HAP metal, fluorine, or chlorine content operating limit set during the performance stack tests. If you plan to burn a new fuel, a fuel from a new mixture, or a new supplier's fuel that differs from what was burned during the initial performance tests, then you must recalculate the maximum Hg, HAP metal, fluorine, and/or chlorine input anticipated from the new fuels based on supplier data or own fuel analysis, using the methodology specified in Table 6 of this proposed rule. If the results of recalculating the inputs exceed the average content levels established during the initial test then, you must conduct a new performance test(s)

to demonstrate continuous compliance with the applicable emission limit.

(7) For existing LEEs, we are proposing that those units that qualify be allowed to demonstrate continuous compliance with the Hg emission limit, the non-Hg HAP metals, or the HCl emissions limits separately or in combination based on fuel analysis rather than performance stack testing. LEE would be those units where performance testing demonstrates that emissions are less than 50 percent of the PM or HCl emissions limits, less than 10 percent of the Hg emissions limits, or less than 22.0 pounds per year (lb/yr) of Hg. Note that for LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volumes shown in Table 2 or this proposed rule must be increased nominally by a factor of two. The LEE cutoff of 22.0 lb/yr represents about 5 percent of the nationwide Hg mass emissions from the coal-fired units represented in the 2010 ICR. Most of the units that emit less than 22.0 lb/yr would be smaller units with relatively low heat input capacities. The 22.0 lb/yr threshold was determined by summing the total Hg emissions from the 1,091 units in operation and determining the 5th percentile of the total mass. The units were then ranked by their annual Hg mass emissions. At the point in the rankings where the cumulative mass was equivalent to the 5th percentile value calculated, the annual mass emissions of that unit (22.0 lb/yr) was selected as the threshold. Five percent of the total mass was chosen as a cut point because comments received on CAMR indicated that 5 percent of the total mass was a reasonable cut point. At this 5th percentile threshold, approximately 394 smaller units out of the 1,091 total units would have the option of using this Hg monitoring methodology.

Under the proposed alternative compliance option, you would maintain fuel records that demonstrate that you burned no new fuels or fuels from a new supplier such that the Hg, non-Hg HAP metal, or the chlorine content of the inlet fuel was maintained at or below your maximum fuel Hg, non-Hg HAP metal, fluorine, or chlorine content operating limit set during the performance stack tests. If you plan to burn a new fuel, a fuel from a new mixture, or a new supplier's fuel that differs from what was burned during the initial performance tests, then you must recalculate the maximum Hg, non-Hg HAP metal, and/or the maximum chlorine input anticipated from the new fuels based on supplier data or own fuel analysis, using the methodology specified in Table 6 of this proposed rule. If the results of recalculating the inputs exceed the average content levels established during the initial test then, you must conduct a new performance test(s) to demonstrate continuous compliance with the applicable emission limit.

(8) For all EGUs, we are proposing that you maintain daily records of fuel use that demonstrate that you have burned no materials that are considered solid waste.

If an owner or operator would like to use a control device other than the ones specified in this section to comply with this proposed rule, the owner/operator should follow the requirements in *40 CFR 63.8(f)*, which establishes the procedure for submitting a request to the Administrator to use alternative monitoring.

2. Streamlined Approach to Continuous Compliance

EPA is proposing to simplify compliance with the proposed rule by harmonizing its monitoring and

reporting requirements, to the extent possible, with those of 40 CFR part 75. With a few exceptions, the utility industry is already required to monitor and report hourly emissions data according to Part 75 under the Title IV ARP and other emissions trading programs. The Agency is, therefore, proposing Hg monitoring requirements that are consistent with Part 75 and similar to those that had been promulgated for the vacated CAMR regulation. We are proposing that hourly Hg emission data be reported to EPA electronically, on a quarterly basis. At this time, we are proposing not to apply the same electronic reporting for certification and QA test data from HCl or PM CEMS but are instead relying on the existing provisions in Parts 60 and 63.

Our rationale for this is as follows. We considered two possible Hg monitoring and reporting options to demonstrate continuous compliance. The first option would be for Hg CEMS and sorbent trap systems to be certified and quality-assured according to PS 12A and 12B in Appendix B to 40 CFR part 60. Procedure 5 in Appendix F to Part 60 would be followed for on-going QA. Semiannual hard copy reporting of "deviations" would be required, along with data assessment reports (DARs). Even though this option would not require electronic reporting of either hourly Hg emissions data or QA test results, it still would require affected sources to have a data handling system (DAHS) that: (1) Is programmed to capture data from the Hg CEMS; (2) uses the criteria in Appendix F to Part 60 to validate or invalidate the Hg data; (3) calculates hourly averages for Hg concentration and for the auxiliary parameters (*e.g.*, flow rate, O[2] or CO[2] concentration) that are needed to convert Hg concentrations to the units of the emission standard; (4) calculates 30 boiler operating day rolling average

Hg emission rates; and (5) identifies any deviations that must be reported to the Agency.

The second option would simply integrate Hg emissions data and QA test results into the existing Part 75-compliant DAHS that is installed at the vast majority of the coal-fired EGUs. We obtained feedback from several DAHS vendors indicating that the cost of modifying the existing Part 75 DAHS systems to accommodate hourly reporting of Hg CEMS and sorbent trap data would be similar, and in some cases, less than the cost of the first option. Also, there would be little or no cost to industry for the flow rate, CO[2], or O[2], and moisture monitors needed to convert Hg concentration to the units of the standard, because, as previously noted, almost all of the EGUs already have these monitors in place. In view of these considerations, we have decided in favor of this second option for Hg.

Requiring the reporting of hourly Hg emissions data from EGUs would be advantageous, both to EPA and industry. The DAHS could be automated to demonstrate compliance with the standard on a continuous basis. The data could then be submitted to the Agency electronically, thereby eliminating the need for the Agency to request additional information for compliance determinations and program implementation.

Today's proposed rule would also require quarterly electronic reporting of hourly SO[2] CEMS data, PM CEMS data, and HCl CEMS data (for sources electing to demonstrate continuous compliance using certified CEMS), as well as electronic summaries of emission test results (for sources demonstrating continuous compliance by periodic stack testing), and semiannual electronic "deviation" reports (for sources that monitor parameters or assess compliance in other ways). As

discussed in detail in the paragraphs below, requiring electronic reporting in lieu of traditional hard copy reports would enable utility sources to demonstrate continuous compliance with the applicable emissions limitations of this proposed rule, using a process that is familiar to them and consistent with the procedures that they currently follow to comply with ARP and other mass-based emissions trading programs.

Currently, utility sources that are subject to the ARP and other EPA emissions trading programs use the Emissions Collection and Monitoring Plan System (ECMPS) to process and evaluate continuous monitoring data and other information in an electronic format for submittal to the Agency. In addition to receiving hourly emissions data, this system supports the maintenance of an electronic "monitoring plan" and is designed to receive the results of monitoring system certification test data and ongoing QA test data. Emissions data are submitted quarterly through ECMPS, and users are given feedback on the quality of their reports before the data are submitted. This allows them to make corrections or otherwise address issues with the reports prior to making their official submittals. Despite the stringency and thoroughness of the data validation checks performed by the ECMPS software, the implementation of this process has resulted in very few errant reports being submitted each quarter. This has saved both industry and the Agency countless hours of valuable time, which in years past, was spent troubleshooting errors in the quarterly reports. EPA is proposing to apply the same basic quarterly data collection process to Hg, HCl, and PM CEMS data, and to modify ECMPS to be able to accommodate summarized stack test data and semiannual deviation reports.

The ECMPS process divides electronic data into three categories, the first of which is monitoring plan data. The electronic monitoring plan is maintained as a separate entity, and can be updated at any time, if necessary. The monitoring plan documents the characteristics of the affected units (*e.g.*, unit type, rated heat input capacity, *etc.*) and the monitoring methodology that is used for each parameter (*e.g.*, CEMS). The monitoring plan also describes the type of monitoring equipment used (hardware and software components), includes analyzer span and range settings, and provides other useful information. Nearly all coal-fired EGUs are subject to the ARP and have established electronic monitoring plans that describe their required SO[2], flow rate, CO[2] or O[2], and, in some cases, moisture monitoring systems. The ECMPS monitoring plan format could easily accommodate this same type of information for Hg, HCl, and PM CEMS, with the addition of a few codes for the new parameters.

The second type of data collected through ECMPS is certification and QA test data. This includes data from linearity checks, relative accuracy test audits (RATAs), cycle time tests, 7-day calibration error tests, and a number of other QA tests that are required to validate the emissions data. The results of these tests can be submitted to EPA as soon as the results are received, with one notable exception. Daily calibration error tests are not treated as individual QA tests, due to the large number of records generated each quarter. Rather, these tests are included in the quarterly electronic reports, along with the hourly emissions data.

The ECMPS system is already set up to receive and process certification and QA data from SO[2], CO[2],

O[2], flow rate, and moisture monitoring systems that are installed, certified, maintained, operated, and quality-assured according to Part 75. EGUs routinely submit these data to EPA under the ARP and other emissions trading programs.

To accommodate the certification and QA tests for Hg CEMS and sorbent trap monitoring systems, relatively few changes would have to be made to the structure and functionality of ECMPS, because most of the tests are the same ones that are required for other gas monitors. More substantive changes to the system would be required to receive and process the certification and QA tests required for HCl and PM CEMS, and to receive summarized stack test results, and the types of data provided in semiannual compliance reports; however, we believe these changes are implementable. Another modification that could be made to ECMPS would be to disable the Part 75 bias test (which is required for certain types of monitors under EPA's emissions trading programs) for Hg, HCl, and PM CEMS, if bias adjustment of the data from these monitors is believed to be unnecessary or inappropriate for compliance with the proposed rule. We are proposing to make this modification and solicit comment on it.

The third type of data collected through ECMPS is the emissions data, which, as previously noted, is reported on a quarterly schedule. The reports must be submitted within 30 days after the end of each calendar quarter. The emissions data format requires hourly reporting of all measured and calculated emissions values, in a standardized electronic format. Direct measurements made with CEMS, such as gas concentrations, are reported in a Monitor Hourly Value (MHV) record. A typical MHV record for gas

concentration includes data fields for: (1) The parameter monitored (*e.g.*, SO[2]); (2) the unadjusted and bias-adjusted hourly concentration values (note that if bias adjustment is not required, only the unadjusted hourly value is reported); (3) the source of the data, *i.e.*, a code indicating either that each reported hourly concentration is a quality-assured value from a primary or backup monitor, or that quality-assured data were not obtained for the hour; and (4) the percent monitor availability (PMA), which is updated hour-by-hour. This generic record structure could easily accommodate hourly average measurements from Hg, HCl, and PM CEMS.

The ECMPS reporting structure is quite flexible, which makes it useful for assessing compliance with various emission limits. The Derived Hourly Value (DHV) record provides the means whereby a wide variety of quantities that can be calculated from the hourly emissions data can be reported. For instance, if an emission limit is expressed in units of lb/MMBtu, the DHV record can be used to report hourly pollutant concentration values in these units of measure, since the lb/MMBtu values can be derived from the hourly pollutant and diluent gas (CO[2] or O[2]) concentrations reported in the MHV records. ECMPS can also accommodate multiple DHV records for a given hour in which more than one derived value is required to be reported. Therefore, if hourly Hg, HCl, and PM concentration data are reported through ECMPS, the DHV record, in conjunction with the appropriate equations and auxiliary information such as heat input and electrical load (all of which are reported hourly in the emissions reports), could be used to report hourly data in the units of the emission standards (*e.g.*, lb/MMBtu, lb/TBtu, lb/GWh, *etc.*).

The ARP and other emissions trading programs that report emissions data to EPA using Part 75 are required to provide a complete data record. Emissions data are required to be reported for every unit operating hour. When CEMS are out of service, substitute data must be reported to fill in the gaps. However, for the purposes of compliance with a NESHAP, reporting substitute data during monitor outages may not be appropriate. Today's proposed rule would not require the use of missing data substitution for Hg monitoring systems. We intend to extend this concept to HCl and PM CEMS, if we receive data from those types of monitors. Hours when a monitoring system is out of service would simply be counted as hours of monitor down time, to be counted against the percent monitor availability. We solicit comment on this proposed approach.

As previously stated, EPA is proposing to add Hg monitoring provisions as Appendix A to 40 CFR part 63, subpart UUUUU, and to require these provisions to be used to document continuous compliance with the proposed rule, for units that cannot qualify as LEEs. Proposed Appendix A would consolidate all of the Hg monitoring provisions in one place. Today's proposed rule would provide two basic Hg continuous monitoring options: Hg CEMS and sorbent trap monitoring systems.

Proposed Appendix A would require the Hg CEMS and sorbent trap monitoring systems to be initially certified and then to undergo periodic QA testing. The certification tests required for the Hg CEMS would be a 7-day calibration error test, a linearity check, using NIST-traceable elemental Hg standards, a 3-level system integrity check (similar to a linearity check), using NIST-traceable oxidized Hg standards, a cycle

time test, and a RATA. A bias test would not be required. The performance specifications for the required certification tests, which are summarized in Table A-1 of proposed Appendix A, would be the same as those that were published in support of CAMR. For ongoing QA of the Hg CEMS, proposed Appendix A would require daily calibrations, weekly single-point system integrity checks, quarterly linearity checks (or 3-level system integrity checks) and annual RATAs. These QA test requirements and the applicable performance criteria, which, once again, are the same as the ones we had published in support of CAMR, are summarized in Table A-3 in proposed Appendix A. For sorbent trap monitoring systems, a RATA would be required for initial certification, and annual RATAs would be required for ongoing QA. The performance specification for these RATAs would be the same as for the RATAs of the Hg CEMS. Bias adjustment of the measured Hg concentration data would not be required. However, for routine, day-to-day operation of the sorbent trap system, proposed Appendix A provides the owner or operator the option to follow the procedures and QA/QC criteria in PS 12B in Appendix B to 40 CFR part 60. Performance Specification 12B is nearly identical to the vacated Appendix K to Part 75. The Part 75 concepts of: (1) Determining the due dates for certain QA tests on the basis of "QA operating quarters"; and (2) grace periods for certain QA tests, would apply to both Hg CEMS and sorbent trap monitoring systems.

Mercury concentrations measured by Hg CEMS or sorbent trap systems would be used together with hourly flow rate, diluent gas, moisture, and electrical load data, to express the Hg emissions in units of the proposed rule, on an hourly basis (*i.e.*, lb/TBtu or lb/GWh). Proposed section 6 of Appendix A provides

the necessary equations for these unit conversions. These hourly values could then be "rolled up" within the DAHS into the proper 30 boiler operating day averaging period, to assess compliance. A report function could be added to ECMPS to show the results of these calculations, and to highlight any values in excess of the standard.

The proposed rule would specify record keeping and reporting requirements for the two Hg monitoring methodologies. Essential information pertaining to each methodology would be represented in the electronic monitoring plan. Hourly Hg concentration data would be reported in all cases. However, for the sorbent trap option, a single Hg concentration value would be reported for extended periods of time, since a sorbent trap monitoring system does not provide hour-by-hour measurements of Hg concentration. The results of all required certification and QA tests would also be reported. Missing data substitution for Hg concentration would not be required for hours in which quality-assured data are not obtained. Special codes would be reported to identify these hours.

Of all the types of NESHAP compliance data that could be brought into ECMPS (*i.e.*, CEMS data, stack test summaries, and semiannual compliance reports), the easiest to implement would be the Hg monitoring data, because, as noted above, we had published specific Hg monitoring and reporting provisions in Part 75 prior to the vacatur of CAMR, and had made considerable progress in modifying ECMPS to receive these data. Today's proposed rule provides detailed regulatory language in proposed Appendix A to 40 CFR part 63, subpart UUUUU, pertaining to the monitoring of Hg emissions and reporting the data electronically.

We are requesting comment on these proposed compliance approaches and on whether our proposed "one stop shopping" approach to reporting MACT compliance information electronically is desirable. In your comments, we ask you to consider the merits of requiring reporting of results from PM CEMS and HCl CEMS to ECMPS and consequent development of a monitoring and reporting scheme for these CEMS that is compatible with ECMPS. If you favor our proposed streamlined continuous compliance approach, we request input on how to make the reporting process user-friendly and efficient. EPA believes that if the essential data that are reported under the Agency's emissions trading programs and the proposed rule are all sent to the same place, this could significantly reduce the burden on industry and bring about national consistency in assessing compliance.

K. What are the notification, recordkeeping, and reporting requirements?

All new and existing sources would be required to comply with certain requirements of the General Provisions (40 CFR part 63, subpart A), which are identified in Table 10 of this proposed rule. The General Provisions include specific requirements for notifications, recordkeeping, and reporting.

Each owner or operator would be required to submit a notification of compliance status report, as required by § 63.9(h) of the General Provisions. This proposed rule would require the owner or operator to include in the notification of compliance status report certifications of compliance with rule requirements.

Except for units that use CEMS for continuous compliance, semiannual compliance reports, as required by § 63.10(e)(3) of subpart A, would be required

for semiannual reporting periods, indicating whether or not a deviation from any of the requirements in the rule occurred, and whether or not any process changes occurred and compliance certifications were reevaluated. As previously discussed, we are proposing to use the ECMPS system to receive the essential information contained in these semiannual compliance reports electronically. For units using CEMS, quarterly electronic reporting of hourly Hg and associated (O[2], CO[2], flow rate, and/or moisture) monitoring data, as well as electronic reporting of monitoring plan data and certification and QA test results, would be required, also through ECMPS.

This proposed rule would require records to demonstrate compliance with each emission limit and work practice standard. These recordkeeping requirements are specified directly in the General Provisions to 40 CFR part 63, and are identified in Table 9 of this proposed rule.

Records of continuously monitored parameter data for a control device if a device is used to control the emissions or CEMS data would be required.

We are proposing that you must keep the following records:

(1) All reports and notifications submitted to comply with this proposed rule.

(2) Continuous monitoring data as required in this proposed rule.

(3) Each instance in which you did not meet each emission limit and each operating limit (*i.e.*, deviations from this proposed rule).

(4) Daily hours of operation by each source.

(5) Total fuel use by each affected liquid oil-fired source electing to comply with an emission limit based on fuel analysis for each 30 boiler operating day period along with a description of the fuel, the total fuel usage amounts and units of measure, and information on the supplier and original source of the fuel.

(6) Calculations and supporting information of chlorine fuel input, as required in this proposed rule, for each affected liquid oil-fired source with an applicable HCl emission limit.

(7) Calculations and supporting information of Hg and HAP metal fuel input, as required in this proposed rule, for each affected source with an applicable Hg and HAP metal (or PM) emission limit.

(8) A signed statement, as required in this proposed rule, indicating that you burned no new fuel type and no new fuel mixture or that the recalculation of chlorine input demonstrated that the new fuel or new mixture still meets chlorine fuel input levels, for each affected source with an applicable HCl emission limit.

(9) A signed statement, as required in this proposed rule, indicating that you burned no new fuels and no new fuel mixture or that the recalculation of Hg and/or HAP metal fuel input demonstrated that the new fuel or new fuel mixture still meets the Hg and/or HAP metal fuel input levels, for each affected source with an applicable Hg and/or HAP metal emission limit.

(10) A copy of the results of all performance tests, fuel analyses, performance evaluations, or other compliance demonstrations conducted to demonstrate initial or continuous compliance with this proposed rule.

(11) A copy of your site-specific monitoring plan developed for this proposed rule as specified in 63 CFR 63.8(e), if applicable.

We are also proposing to require that you submit the following additional notifications:

(1) Notifications required by the General Provisions.

(2) Initial Notification no later than 120 calendar days after you become subject to this subpart.

(3) Notification of Intent to conduct performance tests and/or compliance demonstration at least 60 calendar days before the performance test and/or compliance demonstration is scheduled.

(4) Notification of Compliance Status 60 calendar days following completion of the performance test and/or compliance demonstration.

L. Submission of Emissions Test Results to EPA

EPA must have performance test data to conduct effective reviews of CAA sections 112 and 129 standards, as well as for many other purposes including compliance determinations, emission factor development, and annual emission rate determinations. In conducting these required reviews, EPA has found it ineffective and time consuming, not only for us, but also for regulatory agencies and source owners and operators, to locate, collect, and submit performance test data because of varied locations for data storage and varied data storage methods. In recent years, though, stack testing firms have typically collected performance test data in electronic format, making it possible to move to an electronic data submittal system that would increase the ease and efficiency of data submittal and improve data accessibility.

Through this proposal, EPA is presenting a step to increase the ease and efficiency of data submittal and improve data accessibility. Specifically, EPA is proposing that owners and operators of EGUs submit electronic copies of required performance test reports to EPA's WebFIRE database. The WebFIRE database was constructed to store performance test data for use in developing emission factors. A description of the WebFIRE database is available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.*

As proposed above, data entry would be through an electronic emissions test report structure called the Electronic Reporting Tool (ERT). The ERT would be able to transmit the electronic report through EPA's Central Data Exchange (CDX) network for storage in the WebFIRE database making submittal of data very straightforward and easy. A description of the ERT can be found at http://www.epa.gov/ttn/chief/ert/ert_tool.html.

The proposal to submit performance test data electronically to EPA would apply only to those performance tests conducted using test methods that will be supported by the ERT. The ERT contains a specific electronic data entry form for most of the commonly used EPA reference methods. A listing of the pollutants and test methods supported by the ERT is available at http://www.epa.gov/ttn/chief/ert/ert_tool.html. We believe that industry would benefit from this proposed approach to electronic data submittal. Having these data, EPA would be able to develop improved emission factors, make fewer information requests, and promulgate better regulations.

One major advantage of the proposed submittal of performance test data through the ERT is a standardized method to compile and store much of the

documentation required to be reported by this rule. Another advantage is that the ERT clearly states what testing information would be required. Another important proposed benefit of submitting these data to EPA at the time the source test is conducted is that it should substantially reduce the effort involved in data collection activities in the future. When EPA has performance test data in hand, there will likely be fewer or less substantial data collection requests in conjunction with prospective required residual risk assessments or technology reviews. This would result in a reduced burden on both affected facilities (in terms of reduced manpower to respond to data collection requests) and EPA (in terms of preparing and distributing data collection requests and assessing the results).

State, local, and tribal agencies could also benefit from more streamlined and accurate review of electronic data submitted to them. The ERT would allow for an electronic review process rather than a manual data assessment making review and evaluation of the source provided data and calculations easier and more efficient. Finally, another benefit of the proposed data submittal to WebFIRE electronically is that these data would greatly improve the overall quality of existing and new emissions factors by supplementing the pool of emissions test data for establishing emissions factors and by ensuring that the factors are more representative of current industry operational procedures. A common complaint heard from industry and regulators is that emission factors are outdated or not representative of a particular source category. With timely receipt and incorporation of data from most performance tests, EPA would be able to ensure that emission factors, when updated, represent the most current range of operational

practices. In summary, in addition to supporting regulation development, control strategy development, and other air pollution control activities, having an electronic database populated with performance test data would save industry, state, local, tribal agencies, and EPA significant time, money, and effort while also improving the quality of emission inventories and, as a result, air quality regulations. In this action, as previously stated, EPA is proposing a step to improve data accessibility. Specifically, we are proposing that you submit, to an EPA database, electronic copies of reports of certain performance tests required under the proposed rule through our ERT; however, we request comment on the feasibility of using a modified version of ECMPS, which the utility industry already is familiar with and uses for reporting under the Title IV ARP and other emissions trading programs, to provide this information.

ECPMS could be modified to allow electronic submission of periodic data, including, but not limited to, 30 day averages of parametric data, 30 day average fuel content data, stack test results, and performance of tune up records. These data will need to be submitted and reviewed, and we believe electronic submission via a specific format already in use for other submissions eases understanding, affords transparency, ensures consistency, and saves time and money.

We seek comment on alternatives to the use of a modified ECMPS for electronic data submission. Commenters should describe alternate means for supplying these data and information on associated reliability, the cost, the ease of implementation, and the transparency to the public of the information.

V. Rationale for This Proposed NESHAP

A. How did EPA determine which subcategories and sources would be regulated under this proposed NESHAP?

As stated above, EPA added coal- and oil-fired EGUs to the CAA section 112(c) list on December 20, 2000. This proposed rule proposes standards for the subcategories of coal- and oil-fired EGUs as defined in this preamble. Sources in these subcategories may potentially include combustion units that are at times IB units or solid waste incineration units subject to other standards under CAA section 112 or to standards under CAA section 129. We request comment on whether the proposed rule should address how sources that change fuel input (*e.g.*, burn solid waste or biomass), or otherwise take action that would change the source's applicability (*e.g.*, stop or start selling electricity to the utility power distribution system), must demonstrate continuous compliance with all applicable standards. Note that units subject to another CAA section 112 standard or to solid waste incineration unit standards established under CAA section 129 are not subject to this proposed rule during the period of time they are subject to the other CAA section 112 or 129 standards.

The scope of the EGU source category is limited to coal- and oil-fired units meeting the CAA section 112(a)(8) definition and the proposed definition of "fossil fuel fired" discussed above.

Under CAA section 112(d)(1), the Administrator has the discretion to "* * * distinguish among classes, types, and sizes of sources within a category or subcategory in establishing * * *" standards. For example, differences between given types of units can

lead to corresponding differences in the nature of emissions and the technical feasibility of applying emission control techniques. In the December 2000 listing, EPA initially established and listed two subcategories of fossil fuel-fired EGUs: Coal-fired and oil-fired. The design, operating, and emissions information that EPA has reviewed indicates that there are significant design and operational differences in unit design that distinguish different types of EGUs within these two subcategories, and, because of these differences, we have proposed to establish two subcategories for coal-fired EGUs, two subcategories for oil-fired EGUs, and an IGCC subcategory for gasified coal and solid oil-derived fuel (*e.g.*, petroleum coke), as stated above and discussed further below.

EGU systems are designed for specific fuel types and will encounter problems if a fuel with characteristics other than those originally specified is fired. Changes to the fuel type would generally require extensive changes to the fuel handling and feeding system (*e.g.*, liquid oil-fired EGUs cannot fire solid fuel without extensive modification). Additionally, the burners and combustion chamber would need to be redesigned and modified to handle different fuel types and account for increases or decreases in the fuel volume. In some cases, the changes may reduce the capacity and efficiency of the EGU. An additional effect of these changes would be extensive retrofitting needed to operate using a different fuel. These effects must be considered whether one is discussing two fuel types (*e.g.*, coal vs. oil) or two ranks or forms of fuel within a given fuel type (*e.g.*, gasified vs. solid coal or solid oil-derived fuel).

The design of the EGU, which is dependent in part on the type of fuel being burned, impacts the degree of

combustion, and may impact the level and kind of HAP emissions. EGUs emit a number of different types of HAP emissions. Organic HAP are formed from incomplete combustion and are primarily influenced by the design and operation of the unit. The degree of combustion may be greatly influenced by three general factors: Time, turbulence, and temperature. On the other hand, the amount of fuel-borne HAP (non-Hg metals, Hg, and acid gases) is primarily dependent upon the composition of the fuel. These fuel-borne HAP emissions generally can be controlled by either changing the fuel property before combustion or by removing the HAP from the flue gas after combustion.

We first examined the HAP emissions results to determine if subcategorization by unit design type was warranted. Normally, any basis for subcategorizing (*e.g.*, type of unit) must be related to an effect on emissions, rather than some difference which does not affect emissions performance. We concluded that the data were sufficient for one or more HAP for determining that a distinguishable difference in performance exists based on the following five unit design types: coal-fired units designed to burn coal with greater than or equal to 8,300 Btu/lb (for Hg emissions only); coal-fired units designed to burn coal with less than 8,300 Btu/lb (for Hg emissions only); IGCC units; liquid oil units; and solid oil-derived units. For other types of units noted above (*e.g.*, FBC, stoker, wall-fired, tangential (T)-fired), there was no significant difference in emissions that would justify subcategorization. Because in the five cases different types of units have different emission characteristics for one or more HAP, we have determined that these types of units should be subcategorized. Accordingly, we propose to subcategorize EGUs based on the five unit types.

For Hg emissions from coal-fired units, we have determined that different emission limits for the two subcategories are warranted. There were no EGUs designed to burn a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in an EGU with a height-to-depth ratio of 3.82 or greater among the top performing 12 percent of sources for Hg emissions, indicating a difference in the emissions for this HAP from these types of units. The boiler of a coal-fired EGU designed to burn coal with that heat value is bigger than a boiler designed to burn coals with higher heat values to account for the larger volume of coal that must be combusted to generate the desired level of electricity. Because the emissions of Hg are different between these two subcategories, we are proposing to establish different Hg emission limits for the two coal-fired subcategories. For all other HAP from these two subcategories of coal-fired units, the data did not show any difference in the level of the HAP emissions and, therefore, we have determined that it is not reasonable to establish separate emissions limits for the other HAP.

For all HAP emissions from oil-fired units, we have determined that two subcategories are warranted. EGUs designed to burn a solid fuel (*e.g.*, petroleum coke) derived from the refining of petroleum (oil) are of a different design, and have different emissions, than those designed to burn liquid oil. In addition, EGUs designed to burn liquid oil cannot, in fact, accommodate the solid fuel derived from the refining of oil. Thus, we are proposing to subcategorize oil-fired EGUs into two subcategories based on the type of units designed to burn oil in its different physical states.

EGUs employing IGCC technology combust a synthetic gas derived from solid coal or solid oil-derived fuel. No solid fuel is directly combusted in the unit during operation (although a coal- or solid oil-derived fuel is fired), and both the process and the emissions from IGCC units are different from units that combust solid coal or petroleum coke. Thus, we are proposing to subcategorize IGCC units as a distinct type of EGU for this proposed rule. EPA solicits comment on these subcategorization approaches.

Additional subcategories have been evaluated, including those suggested by the SERs serving on the SBAR established under the SBREFA. These suggestions include subcategorization of lignite coal vs. other coal ranks; subcategorization of Fort Union lignite coal vs. Gulf Coast lignite coal vs. other coal ranks; subcategorization by EGU size (*i.e.*, MWe); subcategorization of base load vs. peaking units (*e.g.*, low capacity utilization units); subcategorization of wall-fired vs. T-fired units; and subcategorization of small, non-profit-owned units vs. other units.

EPA has reviewed the available data and does not believe that these suggested approaches merit subcategorization. For example, there are both large and small units among the EGUs comprising the top performing 12 percent of sources and small entities may own minor portions of large EGUs and/or individual EGUs themselves. In addition, because the proposed format of the standards is lb/MMBtu (or TBtu for Hg), the size should only affect the rate at which a unit generates electricity and, with a lower electricity generation rate, there is less fuel consumption and, therefore, less emissions of fuel-borne HAP (i.e., acid gas and metal HAP). Further, with the exception of IGCC and as noted elsewhere regarding

boiler height-to-depth ratio, there is no indication that EGU type (*e.g.*, wall-fired, T-fired, FBC, stoker-fired), has any impact on HAP emission levels as all of these types are within the top performing 12 percent of sources. There is also little indication that operating load has any significant impact on HAP emissions or on the type of control demonstrated on the unit.

EPA solicits comment on whether we should further subcategorize the source category. In commenting, commenters should provide a definition or threshold that would distinguish the proposed subcategory from the remainder of the EGU population and, to support this distinction, an estimate of how many EGUs would be impacted by the subcategorization approach, the amount of time such impacted units operate, the extent to which such impacted units would move out of and back into the subcategory in a given year (or other period of time), and any other information the commenter believes is pertinent. For example, if a commenter were to suggest subcategorizing low capacity factor or peaking units from the remainder of the EGU population, in addition to the suggested threshold capacity factor, information on the number of such units that would be impacted, the amount of time such units are running (capacity utilization), the extent to which such units are low capacity factor units in a given year vs. operating at a higher capacity factor, and data from the units when operating both as peaking units and as baseload units (among other information) would need to be provided to support the comment. Commenters should further explain how their suggested subcategorizations constitute a "size," "type," or "class," as those terms are used in CAA section 112(d)(1).

B. How did EPA select the format for this proposed rule?

This proposed rule includes numerical emission limitations for PM, Hg, and HCl (as well as for other alternate constituents or groups). Numerical emission limitations provide flexibility for the regulated community, because they allow a regulated source to choose any control technology, approach, or technique to meet the emission limitations, rather than requiring each unit to use a prescribed control method that may not be appropriate in each case.

We are proposing numerical emission rate limitations as a mass of pollutant emitted per heat energy input to the EGU for the fuel-borne HAP for existing sources. The most typical units for the limitations are lb/MMBtu of heat input (or, in the case of Hg, lb/TBtu). The mass per heat input units are consistent with other Federal and many state EGU regulations and allows easy comparison between such requirements. Additionally, this proposed rule contains an option to monitor inlet chlorine, fluorine, non-Hg metal, and Hg content in the liquid oil to meet outlet emission rate limitations. This is reasonable because oil-fired units may choose to remove these fuel-borne HAP from the oil before combustion in lieu of installing air pollution control devices. This option can only be done on a mass basis by liquid oil-fired EGUs. We request comment on the viability of this approach for IGCC units.

We are proposing numerical emission rate limitations as a mass of pollutant emitted per megawatt- or gigawatt-hour (MWh or GWh) gross output from the EGU for the fuel-borne HAP for new sources and as an alternate format for existing sources. An outlet numerical emission limit is also consistent with the

format of other regulations (*e.g.*, the EGU NSPS, 40 CFR part 60, subpart Da).

EGUs can emit a wide variety of compounds, depending on the fuel burned. Because of the large number of HAP potentially present and the disparity in the quantity and quality of the emissions information available, EPA grouped the HAP into five categories based on available information about the pollutants and on experiences gained on other NESHAP: Hg, non-Hg metallic HAP, inorganic (i.e., acid gas) HAP, non-dioxin/furan organic HAP, and dioxin/furan organic HAP. The pollutants within each group have similar characteristics and can be controlled with the same techniques. For example, non-Hg metallic HAP can be controlled with PM controls. We chose to look at Hg separately from other metallic HAP due to its different chemical characteristics and its different control technology feasibility.

Next, EPA identified compounds that could be used as surrogates for all the compounds in each pollutant category. Existing technologies that have been installed to control emissions of other (*e.g.*, criteria) pollutants are expected to provide coincidental or "co-benefit" control of some of the HAP. For example, technologies for PM control (*e.g.*, ESP, FF) can effectively remove Hg that is bound to particulate such as injected sorbents, unburned carbon, or other fly ash particles. Similarly, PM control technologies are effective at reducing emissions of the non-Hg metal HAP that are present in the fly ash as solid particulate. Flue gas desulfurization technologies typically remove SO[2] using acid-base neutralization reactions (usually via contact with alkaline solids or slurries). This approach is also effective for other acid

gases as well, including the acid gas HAP (HCl, HF, Cl[2], and HCN).

EGUs routinely measure operating parameters (flow rates, temperatures, pH, pressure drop, etc.) and flue gas composition for process control and monitoring and for emission compliance and verification. Some of these routinely or more easily-measured parameters or components may serve as surrogates or indicators of the level of control of one or more of the HAP that may not be easily or routinely measured or monitored. The use of more easily-measured components or process conditions as surrogates or predictors of HAP emissions can greatly simplify monitoring requirements under this proposed rule and, in some cases, provide more reliable results.

In order to evaluate potential surrogacy relationships, the EPA Office of Research and Development (ORD), in collaboration with OAR, conducted a series of tests in the Agency's Multipollutant Control Research Facility (MPCRF), a pilot-scale combustion and control technology research facility located at EPA's Research Triangle Park campus in North Carolina. The combustor is rated at 4 MMBtu/hr (approximately 1.2 megawatt-thermal (MW[t])). It is capable of firing all ranks of pulverized coal, natural gas, and fuel oil. The facility is equipped with low NO[X] burners and an SCR unit for NO[X] control. The system can be configured to allow the flue gas to flow through either an ESP or a FF for PM control. The facility also uses a wet lime-based FGD scrubber for control of SO[2] emissions. The system is well equipped with CEMS for on-line measurement of O[2], CO[2], NO[X] (nitrogen oxide, NO, and nitrogen dioxide, NO[2]), SO[2], CO, Hg, and THC. There are multiple sampling ports throughout the flue gas flow

path. The facility is designed for ease of modification so that various control technologies and configurations can be tested. The facility has a series of heat exchangers to remove heat such that the flow path of the flue gas has a similar time-temperature profile to that seen in a typical full-scale coal-fired EGU.

Eleven independent tests were performed in the MPCRF in order to examine potential surrogacy relationships. Three types of coal (eastern bituminous, subbituminous, and Gulf Coast lignite) were tested. The PM control was also varied; in some tests, the ESP was used whereas the FF was used in others. Three potential surrogacy relationships were examined during the testing program. The potential for use of PM control as a surrogate for the control of the non-Hg metal HAP (Be, As, Cd, Co, Cr, Mn, Ni, Pb, Sb, and Se) was examined. The potential for use of HCl or SO[2] control as a surrogate for other acid gases (HCl, HF, Cl[2]) was studied. In addition, several potential surrogate relationships were examined for the non-dioxin/furan organic HAP. No surrogate studies were conducted for Hg; we have not identified any surrogates for Hg and, thus, are regulating Hg directly. No surrogacy studies were conducted for dioxin/furan organic HAP because we believed the S:Cl ratio in the flue gas would be greater than 1.0, meaning that the formation of dioxins/furans would be inhibited. Moreover, it was anticipated that levels of these compounds would be very low, and, as mentioned earlier in the preamble, the approved 2010 ICR sampling methods for dioxin/furan organic HAP required 8-hour sampling periods; such a long sampling period was not practical in our pilot system and would not be practical on a continuous basis.

The results of the program indicated that the control of all non-Hg metal HAP (except Se) was consistently similar to the control of the bulk total PM (PM[total]). The average PM[total] control during the tests was 99.5 percent. All of the non-Hg metal HAP were controlled along with the PM[total] at levels greater than 95 percent for measurements taken for particulate control using both the ESP and the FF. Average control for the test series for each of the metals was (for all coals and all configurations): Sb—95.3 percent; As—98.0 percent; Be—98.5 percent; Cd—98.7 percent; Cr—98.0 percent; Co—99.3 percent; Pb—99.2 percent; Mn—99.5 percent; and Ni—97.6 percent.

The results for Se control were less consistent. When subbituminous coal was fired, the control of Se was consistently very good (average 98.9 percent), regardless of the PM control device being used. When using the FF as the primary PM control device, the Se control was consistently very good (average 99.2 percent) regardless of the coal being fired. Control of Se when the ESP was the primary PM control device was variable. When subbituminous coal was fired, the control of Se through the ESP was greater than 99 percent. When lignite was fired, the control through the ESP was about 80 percent. However, when the eastern bituminous coal was fired, the Se control through the ESP ranged from zero to 73 percent.

The variability in the performance of Se control with coal rank and PM control device can be explained by the known behavior and chemistry of Se in the combustion and flue gas environments. Selenium is a metalloid that sits just below sulfur on the periodic table and is, chemically, very similar to sulfur. In the high temperature combustion environment, Se is likely to be present as gas phase SeO[2] (as, similarly,

sulfur is likely to be present as gaseous SO[2]). Much like SO[2], SeO[2] is a weak acid gas. The testing in the pilot-scale combustion facility showed that Se in the flue gas entering the PM control device tended to be predominantly in the gas phase (55 to 90 percent) when firing eastern bituminous coal and predominantly in the solid phase when firing subbituminous coal (greater than 95 percent) and Gulf Coast lignite (80 percent). This is explained by the large difference in calcium (Ca) content of those fuels. The ash from the bituminous coal contained 1.4 weight percent Ca, whereas the ashes from the subbituminous coal and Gulf Coast lignite contained Ca at 10.0 weight percent and 9.0 weight percent, respectively. The alkaline Ca in the fly ash effectively neutralized the SeO[2] acid gas, forming a particulate that is easily removed in the PM control device. The bituminous fuel contained insufficient free Ca to completely neutralize the SeO[2] and the much increased levels of SO[2] in that flue gas. The good performance through the FF (regardless of the fuel being fired) can be attributed to the increased contact between the gas stream and the filter cake on the FF. This allows more of the SeO[2] to adsorb or condense on fly ash particles—either alkaline particles or unburned carbon. Because SeO[2] behaves very similarly to its sulfur analog, SO[2], it can be expected to also be removed effectively in standard FGD technologies (wet scrubbers, dry scrubbers, DSI, etc.). Therefore, Se will either fall in to the category of "non-Hg metal HAP" and be effectively removed in a PM control device, or it will fall into the category of "acid gas HAP" as gaseous SeO[2] and be effectively removed using FGD technologies.

Two of the 11 tests were specifically designated for testing of surrogacy relationships relating to the acid gas HAP. Eastern bituminous coal was fired and duct

samples were taken upstream and downstream of the lime-based wet FGD scrubber. Those tests showed, as expected, very high levels of control for HCl (greater than 99.9 percent control). The control of HF was greater than 92 percent for the first run and greater than 76 percent for the second run. The control of Cl[2] was greater than 76 percent for the first run and greater than 92 percent for the second run. (Note that both of these control efficiencies were likely much higher than the reported values because the outlet measurements were below the MDL for both HF and Cl[2]. The control efficiencies were calculated using the MDL value.) The control efficiency for SO[2] for the runs was greater than 98 percent.

Tests were also conducted to examine potential surrogacy relationships for the non-dioxin/furan organic HAP. The amounts of Hg, non-Hg metals, HCl, HF, and Cl[2] in the flue gas are directly related to the amounts of Hg, non-Hg metals, chlorine, and fluorine in the coal. Control of these components generally requires downstream control technology. However, the presence of the organics in the flue gas is not related to the composition of the fuel but rather they are a result of incomplete or poor combustion. Control of the organics is often achieved by improving combustion conditions to minimize formation or to maximize destruction of the organics in the combustion environment.

During the pilot-scale tests, sampling was conducted for semi-volatile and volatile organic HAP and aldehydes. On-line monitors also collected data on THC, CO, O[2], and other processing conditions. Total hydrocarbons and CO have been used previously as surrogates for the presence of non-dioxin/furan organics. Carbon monoxide has often been used as an

indicator of combustion conditions. Under conditions of ideal combustion, a carbon-based or hydrocarbon fuel will completely oxidize to produce only CO[2] and water. Under conditions of incomplete or non-ideal combustion, a greater amount of CO will be formed.

With complex carbon-based fuels, combustion is rarely ideal and some CO and concomitant organic compounds are expected to be formed. Because CO and organics are both products of poor combustion, it is logical to expect that limiting the concentration of CO would also limit the production of organics. However, it is very difficult to develop direct correlations between the average concentration of CO and the amount of organics produced during the prescribed sampling period in the MPCRF (which was 4 hours for the pilot-scale tests described here). This is especially true for low values of CO as one would expect corresponding low quantities of organics to be produced. Samples of coal combustion flue gas have mostly shown very low quantities of the organic compounds of interest. Some of the flue gas organics may also be destroyed in the high temperature post combustion zone (whereas the CO would remain stable). Semi-volatile organics may also condense on PM and be removed in the PM control device.

The average CO from the pilot-scale tests ranged from 23 to 137 ppm for the bituminous coals tests, from 43 to 48 ppm for the subbituminous coal tests and from 93 to 129 ppm for the Gulf Coast lignite tests. However, it was difficult to correlate that concentration to the quantity of organics produced for several reasons. The most difficult problems are associated with the large number of potential organics that can be produced (both those on the HAP list and those that are not on the HAP list). This is further complicated

by the organic compounds tending to be at or below the MDL in coal combustion flue gas samples. Further, there are complications associated with the CO concentration values. Some of the runs with very similar average concentrations of CO had very different maximum concentrations of CO (*i.e.*, some of the runs had much more stable emissions of CO whereas others had some excursions, or "spikes," in CO concentration). For example, one of the bituminous runs had an average CO concentration of 69 ppm but a maximum concentration of 1,260 ppm (due to a single "spike" of CO during a short upset). Comparatively, another bituminous run had a higher average CO concentration at 137 ppm but a much lower maximum CO value at 360 ppm.

In the pilot tests, the THC measurement was inadequate as the detection limit of the instrument was much too high to detect changes in the very low concentrations of hydrocarbons in the flue gas.

Based on the testing described above and the emissions data received under the 2010 ICR, we are proposing surrogate standards for the non-Hg metallic HAP and the non-metallic inorganic (acid gas) HAP. For the non-Hg metallic HAP, we chose to use PM as a surrogate. Most, if not all, non-Hg metallic HAP emitted from combustion sources will appear on the flue gas fly-ash. Therefore, the same control techniques that would be used to control the fly-ash PM will control non-Hg metallic HAP. PM was also chosen instead of specific metallic HAP because all fuels do not emit the same type and amount of metallic HAP but most generally emit PM that includes some amount and combination of all the metallic HAP. The use of PM as a surrogate will also eliminate the cost of

performance testing to comply with numerous standards for individual non-Hg metals. Because non-Hg metallic HAP may preferentially partition to the small size particles (i.e., fine particle enrichment), we considered using PM[2.5] as the surrogate, but we determined that total PM (filterable (*i.e.*, PM[2.5]) plus condensable) was the more appropriate surrogate for two reasons. The test method (201A) for measuring PM[2.5] is only applicable for use in exhaust stacks without entrained water droplets. Therefore, the test method for measuring PM[2.5] is not applicable for units equipped with wet scrubbers which are in use at many EGUs today and may be necessary at some additional units to achieve the proposed HCl emission limitations. Thus, we are proposing to use total PM, instead of PM[2.5], as the surrogate for non-Hg metals. However, as discussed elsewhere, we are also proposing alternative individual non-Hg metallic HAP emission limitations as well as total non-Hg metallic HAP emission limitations for all subcategories (total metal HAP emission limitation for the liquid oil-fired subcategory).

For non-metallic inorganic (acid gas) HAP, EPA is proposing setting an HCl standard and using HCl as a surrogate for the other non-metallic inorganic HAP for all subcategories except the liquid oil-fired subcategory. The emissions test information available to EPA indicate that the primary non-metallic inorganic HAP emitted from EGUs are acid gases, with HCl present in the largest amounts. Other inorganic compounds emitted are found in smaller quantities. As discussed earlier, control technologies that reduce HCl indiscriminately control other inorganic compounds such as Cl[2] and other acid gases (*e.g.*, HF, HCN, SeO[2]). Thus, the best controls for HCl are also the best controls for other inorganic acid gas HAP Therefore,

HCl is a good surrogate for inorganic HAP because controlling HCl will result in control of other inorganic HAP emissions (as no liquid oil-fired EGU has an FGD system installed, there is no effective control in use and the surrogacy argument is invalid). As discussed elsewhere, EPA is also proposing to set an alternative equivalent SO[2] emission limit for coal-fired EGUs with some form of FGD system installed as: (1) The controls for SO[2] are also effective controls for HCl and the other acid gas-HAP; and (2) most, if not all, EGUs already have SO[2] CEMS in-place. Thus, SO[2] CEMS could serve as the compliance monitoring mechanism for such units. EGUs without an FGD system installed would not be able to use the alternate SO[2] emission limit, and EGUs must operate their FGD at all times to use the alternate SO[2] emission limit.

EPA is proposing work practice standards for non-dioxin/furan organic and dioxin/furan organic HAP. The significant majority of measured emissions from EGUs of these HAP were below the detection levels of the EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units. As the majority of measurements are so low, doubt is cast on the true levels of emissions that were measured during the tests. Overall, 1,552 out of 2,334, total test runs for dioxin/furan organic HAP contained data below the detection level for one or more congeners, or 67 percent of the entire data set. In several cases, all of the data for a given run were below the detection level; in few cases were the data for a given run all above the detection level. For the non-dioxin/furan organic HAP, for the individual HAP or constituent, between 57 and 89 percent of the run data were comprised of values below the detection level. Overall, the available test methods are technically

challenged, to the point of providing results that are questionable for all of the organic HAP For example, for the 2010 ICR testing, EPA extended the sampling time to 8 hours in an attempt to obtain data above the MDL. However, even with this extended sampling time, such data were not obtained making it questionable that any amount of effort, and, thus, expense, would make the tests viable. Based on the difficulties with accurate measurements at the levels of organic HAP encountered from EGUs and the economics associated with units trying to apply measurement methodology to test for compliance with numerical limits, we are proposing a work practice standard under CAA section 112(h).

We do not believe that this approach is inconsistent with that taken on other NESHAP where we also had issues with data at or below the MDL (*e.g.*, Portland Cement NESHAP; Boiler NESHAP). In the case of the Portland Cement NESHAP, the MDL issue was with HCl (a single compound HAP as opposed to the oftentimes multi-congener organic HAP), and in data from only 3 of 21 facilities. As noted elsewhere in this preamble, we dealt with similar MDL issues with HCl in establishing the limits in this proposed rule. In the case of the Boiler NESHAP, the MDL issue was with the organic HAP. For that rulemaking, the required sampling time during conducting of the associated ICR was 4 hours, as opposed to the 8 hours required in the 2010 ICR. Further, a review of the data indicates that the dioxin/furan HAP levels (a component of the organic HAP) were at least 7 times greater, on average, for coal-fired IB units and 3 times greater, on average, for oil-fired IB units than from similar EGUs. We think this difference is significant from a testing feasibility perspective.

For all the other HAP, as stated above, we are proposing to establish numerical emission rate limitations; however, we did consider using a percent reduction format for Hg (*e.g.*, the percent efficiency of the control device, the percent reduction over some input amount, *etc.*). We determined not to propose a percent reduction standard for several reasons. The percent reduction format for Hg and other HAP emissions would not have addressed EPA's desire to promote, and give credit for, coal preparation practices that remove Hg and other HAP before firing (*i.e.*, coal washing or beneficiation, actions that may be taken at the mine site rather than at the site of the EGU). Also, to account for the coal preparation practices, sources would be required to track the HAP concentrations in coal from the mine to the stack, and not just before and after the control device(s), and such an approach would be difficult to implement and enforce. In addition, we do not have the data necessary to establish percent reduction standards for HAP at this time. Depending on what was considered to be the "inlet" and the degree to which precombustion removal of HAP was desired to be included in the calculation, EPA would need (*e.g.*) the HAP content of the coal as it left the mine face, as it entered the coal preparation facility, as it left the coal preparation facility, as it entered the EGU, as it entered the control devices, and as it left the stack to be able to establish percent reduction standards. EPA believes, however, that an emission rate format allows for, and promotes, the use of precombustion HAP removal processes because such practices will help sources assure they will comply with the proposed standard. Furthermore, a percent reduction requirement would limit the flexibility of the regulated community by requiring the use of a control device. In addition, as discussed in the

Portland Cement NESHAP *(75 FR 55,002;* September 9, 2010), EPA believes that a percent reduction format negates the contribution of HAP inputs to EGU performance and, thus, may be inconsistent with the DC Circuit Court's rulings as restated in *Brick MACT (479 F.3d at 880)* that say, in effect, that it is the emissions achieved in practice (*i.e.*, emissions to the atmosphere) that matter, not how one achieves those emissions. The 2010 ICR data confirm the point relating to plant inputs likely playing a role in emissions in that they indicate that some EGUs are achieving lower Hg emissions to the atmosphere at a lower Hg percent reduction (*e.g.*, 75 to 85 percent) than are other EGUs with higher percent reductions (*e.g.*, 90 percent or greater). For all of these reasons, we are proposing to establish numerical emission standards for HAP emissions from EGUs with the exception of the organic HAP standard which is in the form of work practices.

C. How did EPA determine the proposed emission limitations for existing EGUs?

All standards established pursuant to CAA section 112(d)(2) must reflect MACT, the maximum degree of reduction in emissions of air pollutants that the Administrator, taking into consideration the cost of achieving such emissions reductions, and any nonair quality health and environmental impacts and energy requirements, determines is achievable for each category. For existing sources, MACT cannot be less stringent than the average emission limitation achieved by the best performing 12 percent of existing sources (for which the Administrator has emissions information) for categories and subcategories with 30 or more sources or the best performing 5 sources for subcategories with less than 30 sources. This

requirement determines the MACT floor for existing EGUs. However, EPA may not consider costs or other impacts in determining the MACT floor. EPA must consider cost, nonair quality health and environmental impacts, and energy requirements in connection with any standards that are more stringent than the MACT floor (beyond-the-floor controls).

D. How did EPA determine the MACT floors for existing EGUs?

EPA must consider available emissions information to determine the MACT floors. For each pollutant, we calculated the MACT floor for a subcategory of sources by ranking all the available emissions data obtained through the 2010 ICR[158] from units within the subcategory from lowest emissions to highest emissions (on a lb/MMBtu basis), and then taking the numerical average of the test results from the best performing (lowest emitting) 12 percent of sources.

Therefore, the MACT floor limits for each of the HAP and HAP surrogates are calculated based on the performance of the lowest emitting (best performing) sources in each of the subcategories.

As discussed above, for coal-fired EGUs, EPA established the MACT floors for non-Hg metallic HAP and non-metallic inorganic (acid gas) HAP based on sources representing 12 percent of the number of sources in the subcategory. For Hg from coal-fired units and all HAP from oil-fired units, EPA established the MACT floors based on sources representing 12 percent of the sources for which the Agency had emissions information. The IGCC and solid oil-fired EGU subcategories each have less than 30 units so the

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[158] Earlier data were not used due to concerns related to changes in test and analytical methods.

MACT floors were determined using the 5 best performing sources (or 2 sources for IGCC because there are only 2 such sources in the subcategory). The MACT floor limitations for each of the HAP and HAP surrogates (PM, Hg, and HCl) are calculated based on the performance of the lowest emitting (best performing) sources in each of the subcategories. The initial sort of the respective data to determine the MACT floor pool for analysis was made on the "lb/MMBtu" formatted data; this same pool of EGUs was then used for the "lb/MWh" analysis and all analyses were based on the data provided through the 2010 ICR.

We used the emissions data for those best performing affected sources to determine the emission limitations to be proposed, with an accounting for variability. EPA must exercise its judgment, based on an evaluation of the available data, to determine the level of emissions control that has been achieved by the best performing sources under variable conditions. The DC Circuit Court has recognized that EPA may consider variability in estimating the degree of emission reduction achieved by best-performing sources in setting MACT floors. *See Mossville Envt'l Action Now v. EPA, 370 F.3d 1232, 1241-42 (DC Cir 2004)* (holding EPA may consider emission variability in estimating performance achieved by best-performing sources and may set the floor at a level that best-performing source can expect to meet "every day and under all operating conditions").

In determining the MACT floor limitations, we first determine the floor, which is the level achieved in practice by the average of the top 12 percent of similar sources for subcategories with more than 30 sources. We then assess variability of the best performers by using a statistical formula designed to estimate a

MACT floor level that is achieved by the average of the best performing sources with some confidence (*e.g.*, 99 percent confidence) if the best performing sources were able to replicate the compliance tests in our data base. Specifically, the MACT floor limit is an upper prediction limit (UPL) calculated with the Student's t-test using the TINV function in Microsoft Excel. The Student's t-test has also been used in other EPA rulemakings (*e.g.*, NSPS for Hospital/Medical/ Infectious Waste Incinerators; NESHAP for IB and Portland Cement) in accounting for variability. A prediction interval for a future observation, or an average of future observations, is an interval that will, with a specified degree of confidence, contain the next (or the average of some other pre-specified number of) randomly selected observation(s) from a population. In other words, the prediction interval estimates what the range of future values, or average of future values, will be, based upon present or past background samples taken. Given this definition, the UPL represents the value which we can expect the mean of three future observations (3-run average) to fall below, based upon the results of an independent sample from the same population. In other words, if we were to randomly select a future test condition from any of these sources (*i.e.*, average of 3 runs), we can be 99 percent confident that the reported level will fall at or below the UPL value. To calculate the UPL, we used the average (or sample mean) and an estimate of the standard deviation, which are two statistical measures calculated from the available data. The average is a measure of centrality of the distribution. Symmetric distributions such as the normal are centered around the average. The standard deviation is a common measure of the dispersion of the data set around the average.

We first determined the distribution of the emissions data for the best-performing 12 percent of units within each subcategory prior to calculating UPL values. When the sample size is 15 or larger, one can assume based on the Central Limit theorem, that the sampling distribution of the average or sampling mean of emission data is approximately normal, regardless of the parent distribution of the data. This assumption justifies selecting the normal-distribution based UPL equation for calculating the floor.

When the sample size is smaller than 15 and the distribution of the data is unknown, the Central Limit Theorem can't be used to support the normality assumption. Statistical tests of the kurtosis, skewness, and goodness of fit are then used to evaluate the normality assumption. To determine the distribution of the best performing dataset, we first computed the skewness and kurtosis statistics and then conducted the appropriate small-sample hypothesis tests. The skewness statistic (S) characterizes the degree of asymmetry of a given data distribution. Normally distributed data have a skewness of zero (0). A skewness statistic that is greater (less) than 0 indicates that the data are asymmetrically distributed with a right (left) tail extending towards positive (negative) values. Further, the standard error of the skewness statistic (SES) can be approximated by SES = SQRT(6/N) where N is the sample size. According to the small sample skewness hypothesis test, if S is greater than two times the SES, the data distribution can be considered non-normal. The kurtosis statistic (K) characterizes the degree of peakedness or flatness of a given data distribution in comparison to a normal distribution. Normally distributed data have a kurtosis of 0. A kurtosis statistic that is greater (less) than 0 indicates a relatively peaked (flat) distribution.

Further, the standard error of the kurtosis statistic (SEK) can be approximated by SEK = SQRT(24/N) where N is the sample size. According to the small sample kurtosis hypothesis test, if K is greater than two times the SEK, the data distribution is typically considered to be non-normal.

The skewness and kurtosis hypothesis tests were applied to both the reported test values and the lognormal values (using the LN() function in Excel) of the reported test values. If S and K of the reported data set were both less than twice the SES and SEK, respectively, the dataset was classified as normally distributed. If neither S nor K, or only one of these statistics, were less than twice the SES or SEK, respectively, then we looked at the skewness and kurtosis hypothesis test results conducted for the natural log-transformed data. Then, the distribution most similar to a normal distribution was selected as the basis for calculating the UPL. If the results of the skewness and kurtosis hypothesis tests were mixed for the reported values and the natural log-transformed reported values, we chose the normal distribution to be conservative. We believe this approach is more accurate and obtained more representative results than a more simplistic normal distribution assumption.

Because some of the MACT floor emission limitations are based on the average of a 3-run test, and compliance with these limitations will be based on the same, the UPL for data considered to be normally distributed is calculated by:

$$UPL = \bar{x} + t(0.99, n-1) \times \sqrt{s^2 \times \left(\frac{1}{n} + \frac{1}{m}\right)}$$

Where:

n = the number of test runs

m = the number of test runs in the compliance average

[] = mean of the data from top performing sources calculated as

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

t(0.99, n-1) is the 99th percentile of the T-Student distribution with n-1 degrees of freedom

s<2> = variance of the data from top performing sources calculated as

$$s^2 = \frac{1}{n-1}\left\{\sum_{i=1}^{N}\left(x_i - \bar{x}\right)^2\right\}$$

This calculation was performed using the following Excel function:

Normal distribution: 99% UPL = AVERAGE(Test Runs in Top 12%) + [STDEV(Test Runs in Top 12%) x TINV(2 x probability, n-1 degrees of freedom) *SQRT((1/n)+(1/3))], for a one-tailed t-value (with 2 x probability), probability of 0.01, and sample size of n.

Data from only a single unit was used in establishing the new-source floor. Analysis based solely in these single-data-point-per-unit observations does not capture any within source variability. When additional information (*e.g.*, stack averages) from the past 5 years (from the 2010 ICR) was available, we combined the current and past data and calculated an estimate of the variance term, s<2>, that intends to include the within and between source variability. The most recent data (*e.g.*, single floor average) were used to calculate the average in the UPL equation. The UPL equation for this case was calculated as:

$$\overline{x} + t_{df,.99}\sqrt{s^2\left(\frac{1}{N}+\frac{1}{m}\right)}$$

UPL =

Where:

m = the number of test runs in the compliance average

N = the number of units involved in calculating the average (a single measurement (*e.g.*, floor average) per unit)

n[i] = number of data points (*e.g.*, stack averages) collected in the past for the i<th> source

$$n = N + \sum_{i=1}^{N} n_i$$

number of data points (floor average plus stack averages) available to calculate the variance

df = n-1

x [i] = current information (*e.g.*, single floor average) for the i<th> source

y [i] = past information (*e.g.*, stack average) for the i<th> source

m = the number of future test runs in the compliance average

[] = mean of the data from top performing sources calculated as

$$\overline{x} = \frac{1}{N}\sum_{i=1}^{N} x_i$$

$\overline{y}$ is the grand mean (mean of the current and past information from the top performing sources) calculated as

$$\overline{y} = \frac{1}{n}\left(\sum_{i=1}^{N} x_i + \sum_{i=1}^{N}\sum_{j=1}^{n_i} y_{ij}\right)$$

s<2> = variance calculated as

$$s^2 = \frac{1}{n-1}\left\{\sum_{i=1}^{N}\left(x_i - \overline{\overline{x}}\right)^2 + \sum_{i=1}^{N}\sum_{j=1}^{a}\left(y_{ij} - \overline{\overline{x}}\right)^2\right\}$$

<t>[df,.99] = quantile t-distribution with *df* degrees of freedom at 99 percent confidence level *df* = degrees of freedom = n 1

The calculation of this UPL was performed using the following Excel function:

Normal distribution: 99% UPL = AVERAGE(Test Runs in Top 12%) + [STDEV(Test Runs in Top 12%, stack averages) x TINV(2 x probability, (n-1) degrees of freedom)*SQRT((1/N)+(1/3))], for a one-tailed t-value (with 2 x probability), probability of 0.01, and sample size of n.

The UPL, to test compliance based on a 3-run average and assuming log-normal data, is calculated by (Bhaumik and Gibbons, 2004):

$$UPL = e^{\hat{\mu}+\hat{\sigma}z_{\alpha}} + \frac{z_{\alpha}}{m}\sqrt{me^{2\hat{\mu}+\hat{\sigma}^2}\left(e^{\hat{\sigma}^2}-1\right) + m^2 e^{2\hat{\mu}+\hat{\sigma}^2}\left(\frac{\hat{\sigma}^2}{n} + \frac{\hat{\sigma}^4}{2(n-1)}\right)}$$

Where:
m = the number of test runs in the compliance average
n = the number of test runs
$\hat{\mu}$ = the average of the log transformed data from the top performing sources calculated as

$$\hat{\mu} = \frac{\sum_{i=1}^{n}\log(y_i)}{n}$$

[sigma] = the variance estimate of the log transformed data from the top performing sources calculated as:

$$\hat{\sigma}^2 = \frac{\sum_{i=1}^{n}\left(\log(y_i) - \hat{\mu}\right)^2}{n-1}$$

z[99] = the 99<th>-percentile of the log-normal distribution estimated using the trapezoidal rule approach from the following equation

$$\int_{-\infty}^{z}\left(1-\frac{\sqrt{\beta_{1z}}}{6}(3z-z^3)+\frac{(\beta_{2z}-3)(3-6z^2+z^4)}{24}\right)\phi(z)=.99$$

The calculation of the log-normal based UPL was performed using the following Excel function:

Normal distribution: 99% UPL = EXP (AVERAGE(LN(Test Runs in Top 12%)) + VAR(LN(Test Runs in Top 12%))/2) + (99<TH>-PERCENTILE LOGNORMAL DISTRIBUTION/m)*

SQRT(m*EXP(2* AVERAGE(LN(Test Runs in Top 12%))+ VAR(LN(Test Runs in Top 12%)))* (EXP(VAR(LN(Test Runs in Top 12%)))-1)+m2* EXP(2* AVERAGE(LN(Test Runs in Top 12%))+ VAR(LN(Test Runs in Top 12%)))*(VAR(LN(Test Runs in Top 12%))/n+ VAR(LN(Test Runs in Top 12%))2/(2*(n-1)))).

The 99<th> percentile of the log-normal distribution, z[.99], was calculated following Bhaumik and Gibbons (2004).

Test method measurement imprecision can also be a component of data variability. At very low emissions levels, as encountered in some of the data used to support this proposed rule, the inherent imprecision in the pollutant measurement method has a large influence on the reliability of the data underlying the regulatory floor or beyond-the-floor emissions limit. Of particular concern are those data that are reported near or below a test method's pollutant detection capability. In our guidance for reporting pollutant emissions used to support this proposed rule, we specified the criteria for determining test-specific MDL. Those criteria ensure that there is about a 1 percent probability of an error in deciding that the pollutant measured at the MDL is present when in fact it was absent. Such a probability is also called a

false positive or the alpha, Type I, error. Another view of this probability is that one is 99 percent certain of the presence of the pollutant measured at the MDL. Because of matrix effects, laboratory techniques, sample size, and other factors, MDLs normally vary from test to test. We requested sources to identify (*i.e.*, flag) data which were measured below the MDL and to report those values as equal to the test-specific MDL.

Variability of data due to measurement imprecision is inherently and reasonably addressed in calculating the floor emissions limit when the data distribution, which would include the results of all tests, is significantly above the MDL. Should the data distribution shift such that some or many test results are below the MDL but are reported as MDL values, as is the case for some of our database, then other techniques need to be used to account for data variability. Indeed, under such a shift, the distribution becomes truncated on the lower end, leading to an artificial overabundance of values occurring at the MDL. Such an artificial overabundance of values could, if not adjusted, lead to erroneous floor calculations; those unadjusted floor calculations may be higher than otherwise expected, because no values reported below the MDL are included in the calculation. There is a concern that a floor emissions limit based on a truncated data base may not account adequately for data measurement variability and that a floor emissions limit calculated using values at or near the MDL may not account adequately for data measurement variability, because the measurement error associated with those values provides a large degree of uncertainty—up to 100 percent.

Despite our concern that accounting for measurement imprecision should be an important consideration in calculating the floor emissions limit, we did not adjust the calculated floor for the data used for this proposed rule because we do not know how to develop such an adjustment. We remain open to considering approaches for making such an adjustment, particularly when those approaches acknowledge our inability to detect with certainty those values below the MDL. We request comment on approaches suitable to account for measurement variability in establishing the floor emissions limit when based on measurements at or near the MDL.

As noted above, the confidence level that a value measured at the detection level is greater than 0 is about 99 percent. The expected measurement imprecision for an emissions value occurring at or near the MDL is about 40 to 50 percent. Pollutant measurement imprecision decreases to a consistent relative 10 to 15 percent for values measured at a level about three times the MDL.[159] One approach that we believe could be applied to account for measurement variability would require defining a MDL that is representative of the data used in establishing the floor emissions limitations and also minimizes the influence of an outlier test-specific MDL value. The first step in this approach would be to identify the highest test-specific MDL reported in a data set that is also equal to or less than the floor emissions limit calculated for the data set. This approach has the advantage of relying on the data collected to develop the floor emissions limit

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[159] American Society of Mechanical Engineers, *Reference Method Accuracy and Precision (ReMAP): Phase 1, Precision of Manual Stack Emission Measurements,* CRTD Vol. 60, February 2001.

while to some degree minimizing the effect of a test(s) with an inordinately high MDL (*e.g.*, the sample volume was too small, the laboratory technique was insufficiently sensitive, or the procedure for determining the detection level was other than that specified).

The second step would be to determine the value equal to three times the representative MDL and compare it to the calculated floor emissions limit. If three times the representative MDL were less than the calculated floor emissions limit, we would conclude that measurement variability is adequately addressed and we would not adjust the calculated floor emissions limit. If, on the other hand, the value equal to three times the representative MDL were greater than the calculated floor emissions limit, we would conclude that the calculated floor emissions limit does not account entirely for measurement variability. We then would use the value equal to three times the MDL in place of the calculated floor emissions limit to ensure that the floor emissions limit accounts for measurement variability. This adjusted value would ensure measurement variability is adequately addressed in the floor or the emissions limit. This check was part of the variability analysis for all new MACT floors that had below detection level (BDL) or detection level limited (DLL) run data present in the best controlled data set and resulted in the MACT floors being three times the MDL rather than the UPL in a limited number of instances (see "MACT Floor Analysis (2011) for the Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units" (MACT Floor Memo) in the docket). We request comment on this approach.

As previously discussed, we account for variability in setting floors, not only because variability is an element of performance, but because it is reasonable to assess best performance over time. For example, we know that the HAP emission data from the best performing units are, for the most part, short-term averages, and that the actual HAP emissions from those sources will vary over time. If we do not account for this variability, we would expect that even the units that perform better than the floor on average could potentially exceed the floor emission levels a part of the time which would mean that variability was not properly taken into account. This variability may include the day-to-day variability in the total fuel-borne HAP input to each unit; variability of the sampling and analysis methods; and variability resulting from site-to-site differences for the best performing units. EPA's consideration of variability accounted for that variability exhibited by the data representing multiple units and multiple data values for a given unit (where available). We calculated the MACT floor based on the UPL (upper 99th percentile) as described earlier from the average performance of the best performing units, Student's t-factor, and the variability of the best performing units.

We believe this approach reasonably ensures that the emission limits selected as the MACT floors adequately represent the level of emissions actually achieved by the average of the units in the top 12 percent, considering operational variability of those units. Both the analysis of the measured emissions from units representative of the top 12 percent, and the variability analysis, are reasonably designed to provide a meaningful estimate of the average performance, or central tendency, of the best controlled 12 percent of units in a given subcategory.

A detailed discussion of the MACT floor methodology is presented in the MACT Floor Memo in the docket.

1. Determination of MACT for the Fuel-borne HAP for Existing Sources

In developing the proposed MACT floor for the fuel-borne HAP (non-Hg metals, acid gases, and Hg), as described earlier, we are using PM as a surrogate for non-Hg metallic HAP (except for the liquid oil-fired subcategory) and HCl as a surrogate for the acid gases (except for the liquid oil-fired subcategory). Table 12 of this preamble presents the number of units in each of the subcategories, along with the number of units comprising the best performing units (top 12 percent). Table 12 of this preamble also shows the average emission level of the top 12 percent, and the MACT floor including consideration of variability (99 percent UPL of top 12 percent).

Table 12—Summary of MACT Floor Results for Existing Sources

Subcategory	Parameter	PM	HCl	Mercury
Coal-fired unit designed for coal >/= 8,300 Btu/lb	No. of sources in subcategory	1,091	1,091	1,061.
	No. in MACT floor	131	131	40.
	Avg. of top 12%	0.02 lb/MMBtu	0.0003 lb/MMBtu	0.01 lb/TBtu.
	99% UPL of top 12%	0.030 lb/MMBtu	0.0020 lb/MMBtu	1.0 lb/TBtu.

Table 12—Summary of MACT Floor Results for Existing Sources

Subcategory	Parameter	PM	HCl	Mercury
Coal-fired unit designed for coal < 8,300 Btu/lb	No. of sources in subcategory	1,091	1,091	30.
	No. in MACT floor	131	131.	2.
	Avg. of top 12%	0.02 lb/MMBtu	0.0003 lb/MMBtu	1.* 1 lb/TBtu. (1 lb/TBtu *).
	99% UPL of top 12%	0.030 lb/MMBtu	0.0020 lb/MMBtu	11.0 lb/TBtu. (4.0 lb/TBtu *).
IGCC	No. of sources in subcategory	2	2	2.
	No. in MACT floor	2	2	2.
	Avg.	0.03 lb/MMBtu	0.0002 lb/MMBtu	0.9 lb/TBtu.
	99% UPL	0.050 lb/MMBtu	0.00050 lb/MMBtu	3.0 lb/TBtu.
Solid oil-derived	No. of sources in subcategory	10	10	10.

Table 12—Summary of MACT Floor Results for Existing Sources

Subcategory	Parameter	PM	HCl	Mercury
	No. in MACT floor	5	5	5.
	Avg. of top 5	0.04 lb/MMBtu	0.002 lb/MMBtu	0.09 lb/TBtu.
	99% UPL of top 5	0.20 lb/MMBtu	0.0050 lb/MMBtu	0.20 lb/TBtu.
		Total metals **	HCl	Mercury.
Liquid oil	No. of sources in subcategory	154	154	154.
	No. in MACT floor	7	7	7.
	Avg. of top 12%	0.00002 lb/MMBtu	0.0001 lb/MMBtu	NA.
	99% UPL of top 12%	0.000030 lb/MMBtu	0.00030 lb/MMBtu	NA.

* Beyond-the-floor limit as discussed elsewhere.

** Includes Hg.

NA = Not applicable.

For the "Coal-fired unit designed for coal < 8,300 Btu/lb" subcategory, we used 12 percent of the available data (11 data points), or 2 units, in setting the existing source floor for Hg. For the IGCC subcategory, we used data from both units in setting the existing source floor. For the oil-fired subcategory, we did not include data obtained from EGUs co-firing natural gas in the existing-source MACT floor analysis

because those emissions are not representative of EGUs firing 100 percent fuel oil.

We believe that chlorine may not be a compound generally expected to be present in oil. The ICR data that we have received suggests that in at least some oil, it is in fact present. EPA requests comment on whether chlorine would be expected to be a contaminant in oil and if not, why it is appearing in the ICR data. To the extent it would not be expected, we are taking comment on the appropriateness of an HCl limit. Further, we are proposing a total metals limit for oil-fired EGUs that includes Hg, in lieu of a PM limit, based on compliance through fuel analysis. We solicit comment on whether a PM limit or a total metals limit based on stack testing is an appropriate alternative. We recognize that PM is not an appropriate surrogate for Hg because Hg is not controlled to the same extent by the technologies which control emissions of other HAP metals, but we are soliciting comment as to whether there is anything unique as to oil-fired EGUs that would allow us to conclude that PM is an appropriate surrogate for all HAP metal emissions from such units. We further solicit comment on whether we should be setting a separate standard for Hg if we require end-of-stack testing for a total metals limit. Based on the data we have, that Hg limit would be 0.050 lb/MMBtu (0.000070 lb/GWh) for existing oil-fired units and 0.00010 lb/GWh for new oil-fired units. In this regard, we request additional Hg emissions data from oil-fired EGUs. Although we have some data, additional data would aid in our development of the standards for such units.

2. Determination of the Work Practice Standard

CAA section 112(h)(1) states that the Administrator may prescribe a work practice standard or other

requirements, consistent with the provisions of CAA sections 112(d) or (f), in those cases where, in the judgment of the Administrator, it is not feasible to enforce an emission standard. CAA section 112(h)(2)(B) further defines the term "not feasible" in this context to apply when "the application of measurement technology to a particular class of sources is not practicable due to technological and economic limitations."

As noted earlier, the significant majority of the measured emissions from EGUs of dioxin/furan and non-dioxin/furan organic HAP are at or below the MDL of the EPA test methods even though we required 8 hour test runs. As such, EPA considers it impracticable to reliably measure emissions from these units. As mentioned earlier, because the expected measurement imprecision for an emissions value occurring at or near the MDL is about 40 to 50 percent, we are uncertain of the true levels of organic HAP emissions that would be obtained during any test program. Overall, the fact that the organic HAP emission levels found at EGUs are so near the MDL achievable by the available test methods indicates that the results obtained are questionable for all of the organic HAP.

Because the levels of organic HAP emissions from EGUs are so low (at or below the MDL of the available test methods), there is no indication that expending additional cost (*i.e.*, extending the sampling time) would provide the regulated community the ability to test for these HAP that would provide reliable, technically viable results. In fact, the 2010 ICR testing required a longer testing period than normally used and the results were still predominantly below the MDL. Because of the technical infeasibility, the

economic infeasibility is that sources do not have a way to demonstrate compliance that is legitimate and we conclude no additional cost will improve the results.

Based on this analysis, and considering the fact that regardless of the cost, the resulting emissions data would be suspect due to the detection level issues, the Administrator is proposing under CAA section 112(h) that it is not feasible to enforce emission standards for dioxin/furan and non-dioxin/furan organic HAP because of the technological and economic infeasibility described above. Thus, a work practice, as discussed below, is being proposed to limit the emission of these HAP for existing EGUs.

For existing units, the only work practice we identified that would potentially control these HAP emissions is an annual performance test. Organic HAP are formed from incomplete combustion of the fuel. The objective of good combustion is to release all the energy in the fuel while minimizing losses from combustion imperfections and excess air. The combination of the fuel with the O[2] requires temperature (high enough to ignite the fuel constituents), mixing or turbulence (to provide intimate O[2] -fuel contact), and sufficient time (to complete the process), sometimes referred to the three Ts of combustion. Good combustion practice (GCP), in terms of combustion units, could be defined as the system design and work practices expected to minimize the formation and maximize the destruction of organic HAP emissions. We maintain that the proposed work practice standards will promote good combustion and thereby minimize the organic HAP emissions we are proposing to regulate in this manner.

E. How did EPA consider beyond-the-floor options for existing EGUs?

Once the MACT floors were established for each subcategory, we considered various regulatory options more stringent than the MACT floor level of control (*i.e.*, technologies or other work practices that could result in lower emissions) for the different subcategories.

Except for one subcategory, we could not identify better HAP emissions reduction approaches that could achieve greater emissions reductions of HAP than the control technology combination(s) (*e.g.*, FF, carbon injection, scrubber, and GCP) that we expect will be used to meet the MACT floor levels of control (and that are already in use on EGUs comprising the top performing 12 percent of sources), though we did consider duplicate controls (*e.g.*, multiple scrubbers) in series and found the cost of that option unreasonable.

Fuel switching to natural gas is an option that would reduce HAP emissions. We determined that fuel switching was not an appropriate beyond-the-floor option. First, natural gas supplies are not available in some areas. Natural gas pipelines are not available in all regions of the U.S., and natural gas may not be available as a fuel for many EGUs. Moreover, even where pipelines provide access to natural gas, supplies of natural gas may not be adequate, especially during peak demand (*e.g.*, the heating season). Under such circumstances, there would be some units that could not comply with a requirement to switch to natural gas. While the combined capital cost and O&M costs for a coal-to-gas retrofit could be less than that of a combined retrofit with ACI and either DSI or FGD, the increased fuel costs of coal-to-gas cause its total incremental COE at a typical EGU is likely to be

significantly larger than the incremental COE of the other retrofit options available. For example, an EPA analysis detailed in an accompanying TSD found that the incremental COE of coal-to-gas was 4 to 22 times the cost of alternatives, although the magnitude of the difference would change with alternative fuel price assumptions. EPA, therefore, concludes that the coal-to-gas option is not a cost-effective means of achieving HAP reductions for the purposes of this proposed rule.

Additional detail on the economics of coal-to-gas conversion and illustrative calculations of additional emission reductions versus cost impacts are provided in the "Coal-to-Gas Conversion" TSD in the docket.

As noted earlier, no EGU designed to burn a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in a EGU with a height-to-depth ratio of 3.82 or greater was found among the top performing 12 percent of sources for Hg emissions, even though some of these units employed ACI. EPA has learned that the units of this design that were using ACI during the testing were using ACI to meet their permitted Hg emission levels. However, EPA believes that the control level being achieved is still not that which could be achieved if ACI were used to its fullest extent. Therefore, EPA is proposing to establish a beyond-the-floor emission limit for existing EGUs designed to burn a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in a EGU with a height-to-depth ratio of 3.82 or greater. The proposed emission limit is 4 lb/TBtu for existing EGUs in this class. This proposed emission limit is based on use of the data from the top performing unit in the subcategory made available to the Agency

through the 2010 ICR; the same statistical analyses were conducted as were done to establish the MACT floor values for the other HAP. EPA notes that our analysis shows that the technology installed to achieve the MACT floor limit would be the same technology used to achieve the beyond-the-floor MACT limit and, thus, proposing to go beyond-the-floor is reasonable. EPA solicits comment on whether it is appropriate to propose a beyond-the-floor limit for existing EGUs in this subcategory.

To assess the impacts on the existing EGUs in this subcategory to implement the proposed beyond-the-floor limit, EPA conducted analyses using approaches as discussed in the memoranda "Beyond-the-Floor Analysis (2011) for the Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units" and "Emission Reduction Costs for the Beyond-the-Floor Mercury Rate in the Toxics Rule" in the docket. The cost effectiveness of the beyond-the-floor option ranged from $ 17,375 to $ 21,393/lb Hg removed in the two approaches. The total costs of the non-air environmental impacts for the proposed beyond-the-floor limit for this subcategory are estimated as $ 12,310. Non-air quality health impacts were evaluated, but no incremental health impacts were attributable to installation of FF and ACI, because these technologies do not expose electric utility employees or the public to any additional health risks above the risks attributable to current utility operations involving compressed air systems, confined spaces, and exposure to fly ash.

EPA is aware that there may be other means of enhancing the removal of Hg from the flue gas stream (*e.g.*, spraying a halogen such as chlorine or bromine

on the coal as it is fed to the EGU). EPA has information that indicates that such means were employed by an unknown number of EGUs during the period of time they were testing to provide data in compliance with the 2010 ICR (*See* McMeekin memo in the docket). Thus, we believe that the performance of such means is reflected in the MACT floor analysis. However, EPA has no data upon which to assess whether any other technology would provide additional control to that already shown by the use of ACI and, thus, we are not proposing to use such technologies as the basis for a beyond-the-floor analysis. EPA solicits comment on this approach.

EPA believes the best potential way of reducing Hg emissions from existing IGCC units is to remove Hg from the syngas before combustion. For example, an existing industrial coal gasification unit has demonstrated a process, using a sulfur-impregnated AC bed, which has proven to yield over 90 percent Hg removal from the coal syngas. (Rutkowski 2002.) We considered using carbon bed technology as beyond-the-floor for existing IGCC units. However, we have no detailed data to support this position at this time and, thus, are not proposing a beyond-the-floor limit for existing IGCC units. EPA requests comments on whether the use of this or other control techniques have been demonstrated to consistently achieve emission levels that are lower than levels from similar sources achieving the proposed existing MACT floor level of control. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs, including retrofit costs.

We considered proposing beyond-the-floor requirements for Hg in the other subcategories and for the

other HAP in all of the subcategories. Activated carbon injection is used on EGUs designed for coal greater than or equal to 8,300 Btu/lb and, therefore, its effect on Hg removal has already been accounted for in the MACT floor. Further, EPA has no information that would indicate that ACI would provide significantly lower emission levels given the MACT floor Hg standard, and it is also possible that existing sources in this subcategory will utilize ACI to comply with the MACT floor limit. Activated carbon injection has not been demonstrated on liquid oil-fired EGUs. Similarly, ACI has not been demonstrated on solid oil-derived fuel-fired EGUs. EPA has no information that would indicate that ACI would provide significantly lower Hg emission levels on units operating at the level of the MACT floor. For the non-Hg metallic and acid gas HAP, there is no technology that would achieve additional control over that being shown by units making up the floor. Additional combinations of controls (*e.g.*, dual FGD systems in series) could be used but at a significant additional cost and, given the MACT floor level of control, a minimal additional reduction in HAP emissions. For the organic HAP, EPA is not aware of any measures beyond those proposed here that would result in lower emissions. Therefore, EPA is not proposing beyond-the-floor limitations other than as noted above.

F. Should EPA consider different subcategories?

EPA has attempted to identify subcategories that provide the most reasonable basis for grouping and estimating the performance of generally similar units using the available data. We believe that the subcategories we selected are appropriate.

EPA requests comments on whether additional or different subcategories should be considered. Comments should include detailed information regarding why a new or different subcategory is appropriate (based on the available data and on the statutory constraint of "class, type or size"), how EPA should define any additional and/or different subcategories, how EPA should account for varied or changing fuel mixtures, and how EPA should use the available data to determine the MACT floor for any new or different subcategories.

G. How did EPA determine the proposed emission limitations for new EGUs?

All standards established pursuant to CAA section 112 must reflect MACT, the maximum degree of reduction in emissions of air pollutants that the Administrator, taking into consideration the cost of achieving such emissions reductions, and any nonair quality health and environmental impacts and energy requirements, determines is achievable for each category. The CAA specifies that MACT for new EGUs shall not be less stringent than the emission control that is achieved in practice by the best-controlled similar source. This minimum level of stringency is the MACT floor for new units. However, EPA may not consider costs or other impacts in determining the MACT floor. EPA must consider cost, nonair quality health and environmental impacts, and energy requirements in connection with any standards that are more stringent than the MACT floor (beyond-the-floor controls).

H. How did EPA determine the MACT floor for new EGUs?

Similar to the MACT floor process used for existing EGUs, the approach for determining the MACT floor must be based on available emissions test data. Using such an approach, we calculated the MACT floor for a subcategory of sources by ranking the 2010 ICR emissions data from EGUs within the subcategory from lowest to highest (on a lb/MMBtu basis) to identify the best controlled similar source. The MACT floor limitations for each of the HAP and HAP surrogates (PM, Hg, and HCl) are calculated based on the performance (numerical average) of the lowest emitting (best controlled) source for each pollutant in each of the subcategories.

The MACT floor limitations for new sources were calculated using the same formula as was used for existing sources with one exception. For the new source calculations, the results of the three individual emission test runs were used instead of the 3-run average that was used in determining the existing-source MACT floor. This was done to be able to provide some measure of variability. As previously discussed, we account for variability of the best-controlled source in setting floors, not only because variability is an element of performance, but because it is reasonable to assess best performance over time. We calculated the MACT floor based on the UPL (upper 99th percentile) as described earlier from the average performance of the best controlled similar source, Student's t-factor, and the total variability of the best-controlled source.

This approach reasonably ensures that the emission limit selected as the MACT floor adequately represents the average level of control actually achieved by

the best controlled similar source, considering ordinary operational variability.

A detailed discussion of the MACT floor methodology is presented in the MACT Floor Memo in the docket.

The approach that we use to calculate the MACT floors for new sources is somewhat different from the approach that we use to calculate the MACT floors for existing sources. Although the MACT floors for existing units are intended to reflect the performance achieved by the average of the best performing 12 percent of sources, the MACT floors for new units are meant to reflect the emission control that is achieved in practice by the best controlled similar source. Thus, for existing units, we are concerned about estimating the central tendency of a set of multiple units, whereas for new units, we are concerned about estimating the level of control that is representative of that achieved by a single best controlled source. As with the analysis for existing sources, the new EGU analysis must account for variability.

1. Determination of MACT for the Fuel-Borne HAP for New Sources

In developing the MACT floor for the fuel-borne HAP (PM, HCl, and Hg), as described earlier, we are using PM as a surrogate for non-Hg metallic HAP and HCl as a surrogate for the acid gases (except for the liquid oil-fired subcategory). Table 13 of this preamble presents for each subcategory and fuel-borne HAP the average emission level of the best controlled similar source and the MACT floor which accounts for variability (99 percent UPL).

Table 13—Summary of MACT Floor Results for New Sources

Subcategory	Parameter	PM	HCl	Mercury
Coal-fired unit designed for coal >/= 8,300 Btu/lb	Avg. of top performer	0.03 lb/MWh	0.2 lb/GWh	0.00001 lb/GWh.
	99% UPL of top performer (test runs)	0.050 lb/MWh	0.30 lb/GWh	0.000010 lb/GWh.
Coal-fired unit designed for coal < 8,300 Btu/lb	Avg. of top performer	0.03 lb/MWh	0.2 lb/GWh	0.02 lb/GWh.
	99% UPL of top performer (test runs)	0.050 lb/MWh	0.30 lb/GWh	0.040 lb/GWh.
IGCC	Avg. of top performer	N/A	N/A	N/A.
	99% UPL of top performer (test runs)	0.050 lb/MWh *	0.30 lb/GWh *	0.000010 lb/GWh.*
Solid oil-derived	Avg. of top performer	0.04 lb/MWh	0.0003 lb/MWh	0.0007 lb/GWh.
	99% UPL of top performer (test runs)	0.050 lb/MWh	0.00030 lb/MWh	0.0020 lb/GWh.
		Total metals **	HCl	Mercury

Table 13—Summary of MACT Floor Results for New Sources

Subcategory	Parameter	PM	HCl	Mercury
Liquid oil	Avg. of top performer	0.00009 lb/MMBtu	0.0002 lb/MWh	NA.
	99% UPL of top performer (test runs)	0.00040 lb/MMBtu	0.00050 lb/MWh	NA.

* Beyond-the-floor as discussed elsewhere.

** Includes Hg.

NA = Not applicable.

2. Determination of the Work Practice Standard

We are proposing a work practice standards for non-dioxin/furan organic and dioxin/furan organic HAP under CAA section 112(h) that would require the implementation of an annual performance test program for new EGUs. This proposal for new EGUs is based on the same reasons discussed previously for existing EGUs. That is, the measured emissions from EGUs of these HAP are routinely below the detection limits of the EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units.

Thus, the work practice discussed above for existing EGUs is being proposed to limit the emissions of non-dioxin/furan organic and dioxin/furan organic HAP for new EGUs.

We request comments on this approach.

I. How did EPA consider beyond-the-floor for new units?

The MACT floor level of control for new EGUs is based on the emission control that is achieved in practice by the best controlled similar source within each of the subcategories. No technologies were identified that would achieve HAP reduction greater than the new source floors for the subcategories, except for multiple controls in series (*e.g.*, multiple FFs) which we consider to be unreasonable from a cost perspective.

Fuel switching to natural gas is a potential regulatory option beyond the new source floor level of control that would reduce HAP emissions. However, natural gas supplies are not available in some areas. Thus, this potential control option may be unavailable to many sources in practice. Limited emissions reductions in combination with the high cost of fuel switching and considerations about the availability and technical feasibility of fuel switching makes this an unreasonable regulatory option that was not considered further. As discussed above, the uncertainties associated with nonair quality health and environmental impacts also argue against determining that fuel switching is reasonable beyond-the-floor option. In addition, even if we determined that natural gas supplies were available in all regions, we would still not adopt this fuel switching option because it would effectively prohibit new construction of coal-fired EGUs and we do not think that is a reasonable approach to regulating HAP emissions from EGUs.

Although, as discussed earlier for existing EGUs, EPA is proposing to establish a beyond-the-floor emission limit for Hg for existing EGUs designed to burn a nonagglomerating fuel having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in a EGU with a height-to-depth

ratio of 3.82 or greater, EPA is not proposing to go beyond-the-floor for new EGUs in this subcategory. The proposed emission limit of 0.04 lb/GWh for new EGUs in this subcategory is based on use of ACI on a new unit and, we believe, reflects a level of performance achievable and, as noted above, no technologies were identified that would achieve HAP reduction greater than the new source floors for the subcategories, except for multiple controls in series (*e.g.*, multiple FFs) which we consider to be unreasonable from a cost perspective.

As discussed earlier, because of a lack of data, EPA is not proposing beyond-the-floor emission limits for existing IGCC units. However, EPA believes that the new-source limits derived from the data obtained from the two operating IGCC units are not representative of what a new IGCC unit could achieve. Therefore, EPA looked to the permit issued for the Duke Energy Edwardsport IGCC facility currently under construction.[160] The permitted limits for this unit are similar to the limits derived from the existing units. Because of advances in technology, EPA does not believe that even these permitted levels are representative of what a modern IGCC unit could achieve. The emissions from IGCC units are normally predicted to be similar to or lower than those from traditional pulverized coal (PC) boilers. For example, DOE projects that future IGCC units will be able to meet a PM (filterable) emissions limit of 0.0071 lb/MMBtu, a SO[2] emissions limit of 0.0127 lb/MMBtu, and a Hg emissions limit of

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[160] Letter from Matthew Stuckey, State of Indiana, to Mack Sims, Duke Energy Indiana. Operating permit fo Edwardsport Generating Station IGCC. Undated.

0.571 lb/TBtu.[161] Therefore, we are proposing that the new-source limits for new IGCC units be identical to those of new coal-fired units designed for coal greater than or equal to 8,300 Btu/lb. However, EPA has no information upon which to base the costs and non-air quality health, environmental, and energy impacts of this proposed approach. EPA solicits comment on this approach. Commenters should provide data that support their comment, including costs, emissions data, or engineering analyses.

Similarly, for the reasons discussed earlier for existing EGUs, EPA is not proposing any other beyond-the-floor emission limitations. EPA requests comments on whether the use of any control techniques have been demonstrated to consistently achieve emission levels that are lower than levels from similar sources achieving the proposed new-source MACT floor levels of control. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs, including retrofit costs.

J. Consideration of Whether To Set Standards for HCl and Other Acid Gas HAP Under CAA Section 112(d)(4)

We are proposing to set a conventional MACT standard for HCl and, for the reasons explained elsewhere, are proposing that the HCl limit also serve as a surrogate for other acid gas HAP. We also considered whether it was appropriate to exercise our discretionary authority to establish health-based emission standards under CAA section 112(d)(4) for

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[161] DOE. Overview—Bituminous & Natural Gas to Electricity; Overview of Bituminous Baseline Study. From: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.

HCl and each of the other relevant HAP acid gases: Cl[2], HF, SeO[2], and HCN[162] (because if it were regulated under CAA section 112(d)(4), HCl may no longer be the appropriate surrogate for these other HAP).[163] This section sets forth the requirements of CAA section 112(d)(4); our analysis of the information available to us that informed the decision on whether to exercise discretion; questions regarding the application of CAA section 112(d)(4); and our explanation of how this case relates to prior decisions EPA has made under CAA section 112(d)(4) with respect to HCl.

As a general matter, CAA section 112(d) requires MACT standards at least as stringent as the MACT floor to be set for all HAP emitted from major sources. However, CAA section 112(d)(4) provides that for HAP with established health thresholds, the Administrator has the discretionary authority to consider such health thresholds when establishing emission standards under CAA section 112(d). This provision is intended to allow EPA to establish emission standards other than conventional MACT standards, in cases where a less stringent emission standard will still ensure that

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[162] Before considering whether to exercise her discretion under CAA section 112(d)(4) for a particular pollutant, the Administrator must first conclude that a health threshold has been established for the pollutant.

[163] Hydrogen chloride can serve as a surrogate for the other acid gases in a technology-based MACT standard, because the control technology that would be used to control HCl would also reduce the other acid gases. By contrast, HCl would not be an appropriate surrogate for a health-based emission standard that is protective against the potential adverse health effects from the other acid gases, because these gases (*e.g.*, HF) can act on biological organisms in a different manner than HCl, and each of the acid gases affects human health with a different dose-response relationship.

the health threshold will not be exceeded, with an ample margin of safety. In order to exercise this discretion, EPA must first conclude that the HAP at issue has an established health threshold and must then provide for an ample margin of safety when considering the health threshold to set an emission standard.

It is clear the Administrator may exercise her discretionary authority under CAA section 112(d)(4) only with respect to pollutants with a health threshold. Where there is an established threshold, the Administrator interprets CAA section 112(d)(4) to allow her to weigh additional factors, beyond any established health threshold, in making a judgment whether to set a standard for a specific pollutant based on the threshold, or instead follow the traditional path of developing a MACT standard after determining a MACT floor. In deciding whether to exercise her discretion for a threshold pollutant for a given source category, the Administrator interprets CAA section 112(d)(4) to allow her to take into account factors such as the following: the potential for cumulative adverse health effects due to concurrent exposure to other HAP with similar biological endpoints, from either the same or other source categories, where the concentration of the threshold pollutant emitted from the given source category is below the threshold; the potential impacts on ecosystems of releases of the pollutant; and reductions in criteria pollutant emissions and other co-benefits that would be achieved by a MACT standard. Each of these factors is directly relevant to the health and environmental outcomes at which CAA section 112 is fundamentally aimed. If the Administrator does determine that it is appropriate to set a standard based on a health threshold, she must develop emission standards that will ensure the public will not

be exposed to levels of the pertinent HAP in excess of the health threshold, with an ample margin of safety.

EPA has exercised its discretionary authority under CAA section 112(d)(4) in a handful of prior rules setting emissions standards for other major source categories, including the Boiler NESHAP issued in 2004, which was vacated on other grounds by the DC Circuit Court. In the Pulp and Paper NESHAP *(63 FR 18765;* April 15, 1998), and Lime Manufacturing NESHAP *(67 FR 78054;* December 20, 2002), EPA invoked CAA section 112(d)(4) for HCl emissions for discrete units within the facility. In those rules, EPA concluded that HCl had an established health threshold (in those cases it was interpreted as the RfC for chronic effects) and HCl was not classified as a human carcinogen. In light of the absence of evidence of carcinogenic risk, the availability of information on non-carcinogenic effects, and the limited potential health risk associated with the discrete units being regulated, EPA concluded that it was appropriate to exercise its discretion under CAA section 112(d)(4) for HCl under the circumstances of those rules. EPA did not set an emission standard based on the health threshold; rather, the exercise of EPA's discretion in those cases in effect exempted HCl from the MACT requirement. In more recent rules, EPA decided not to propose a health-based emission standard for HCl emissions under CAA section 112(d)(4) for Portland Cement facilities *(75 FR 54970* (September 9, 2010), and for Industrial, Commercial, and Institutional Boilers, *(75 FR 32005;* June 4, 2010 proposal(major); the final major source rule was signed on February 21, 2011 but has not yet been published). EPA has never

implemented a NESHAP that used CAA section 112(d)(4) with respect to HF, Cl[2], SeO[2], or HCN.[164]

Because any emission standard under CAA section 112(d)(4) must consider the established health threshold level, with an ample margin of safety, in this rulemaking EPA has considered the adverse health effects of the HAP acid gases, beginning with HCl and including HF, Cl[2], SeO[2], and HCN. Research indicates that HCl is associated with chronic respiratory toxicity. In the case of HCl, this means that chronic inhalation of HCl can cause tissue damage in humans. Among other things, it is corrosive to mucous membranes and can cause damage to eyes, nose, throat, and the upper respiratory tract as well as pulmonary edema, bronchitis, gastritis, and dermatitis. Considering this respiratory toxicity, EPA has established a chronic RfC for the inhalation of HCl of 20 micrograms per cubic meter ([mu]g/m<3>). An RfC is defined as an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups[165]) that is likely to be without an appreciable risk of deleterious effects during a lifetime. The development of the RfC for HCl reflected data only on its chronic respiratory toxicity. It did not take into account effects associated with acute exposure,[166] and, in this situation, the IRIS

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[164] EPA has not classified HF, Cl[2], SeO[2], or HCN with respect to carcinogenicity. However, at this time the Agency is not aware of any data that would suggest any of these HAP are carcinogens.

[165] "Sensitive subgroups" may refer to particular life stages, such as children or the elderly, or to those with particular medical conditions, such as asthmatics.

[166] California EPA considered acute toxicity and established a 1-hour reference exposure level (REL) of 2.1 milligrams per cubic

health assessment did not evaluate the potential carcinogenicity of HCl (on which there are very limited studies). As a reference value for a single pollutant, the RfC also did not reflect any potential cumulative or synergistic effects of an individual's exposure to multiple HAP or to a combination of HAP and criteria pollutants. As the RfC calculation focused on health effects, it did not take into account the potential environmental impacts of HCl.

With respect to the potential health effects of HCl, we note the following:

(1) Chronic exposure to concentrations at or below the RfC is not expected to cause chronic respiratory effects;

(2) Little research has been conducted on its carcinogenicity. The one occupational study of which we are aware found no evidence of carcinogenicity;

(3) There is a significant body of scientific literature addressing the health effects of acute exposure to HCl (for a summary, *See* California Office of Health Hazard Assessment, 2008. Acute Toxicity Summary for Hydrogen Chloride, http://www.oehha.ca.gov/air/hot_spots/2008/AppendixD2_final.pdf#page=112 EPA, 2001). In addition, we note that several researchers have shown associations between acid gases and reduced lung function and asthma in North American children.[167] However, we currently lack

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meter (mg/m<3>). An REL is the concentration level at or below which no adverse health effects are anticipated for a specified exposure duration. RELs are designed to protect the most sensitive individuals in the population by the inclusion of margins of safety.

[167] Dockery DW, Cunningham J, Damokosh AI, Neas LM, Spengler JD, Koutrakis P, Ware JH, Raizenne M, Speizer FE.

information on the peak short-term emissions of HCl from EGUs, which might allow us to determine whether a chronic health-based emission standard for HCl would ensure that acute exposures will not pose any health concerns, and;

(4) We are aware of no studies explicitly addressing the toxicity of mixtures of HCl with other respiratory irritants. However, many of the other HAP (and criteria pollutants) emitted by EGUs also are respiratory irritants, and in the absence of information on interactions, EPA assumes an additive cumulative effect (Supplementary Guidance for Conducting Health Risk Assessment of Chemical Mixtures. http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=20533). The fact that EGUs can be located in close proximity to a wide variety of industrial facilities makes predicting and assessing all possible mixtures of HCl and other emitted air pollutants difficult, if not impossible.

In addition to potential health impacts, the Administrator also has evaluated the potential for environmental impacts when considering whether to exercise her discretion under CAA section 112(d)(4). When HCl gas encounters water in the atmosphere, it forms an acidic solution of hydrochloric acid. In areas where the deposition of acids derived from emissions of sulfur and NO[X] are causing aquatic and/or terrestrial acidification, with accompanying ecological

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1996. Health Effects of Acid Aerosols on North American Children: Respiratory Symptoms. Environmental Health Perspectives 104(5):500-504; Raizenne M, Neas LM, Damokosh AI, Dockery DW, Spengler JD, Koutrakis P, Ware JH, Speizer FE. 1996. Health Effects of Acid Aerosols on North American Children: Pulmonary Function. Environmental Health Perspectives 104(5):506-514.

impacts, the deposition of hydrochloric acid could exacerbate these impacts. Recent research [168] has suggested that deposition of airborne HCl has had a greater impact on ecosystem acidification than previously thought, although direct quantification of these impacts remains an uncertain process. We maintain it is appropriate to consider potential adverse environmental effects in addition to adverse health effects when setting an emission standard for HCl under CAA section 112(d)(4).

Because the statute requires an ample margin of safety, it would be reasonable to set any CAA section 112(d)(4) emission standard for a pollutant with a health threshold at a level that at least assures that persons exposed to emissions of the pollutant would not experience the adverse health effects on which the threshold is based due to sources in the controlled category or subcategory. In the case of this proposed rulemaking, we have concluded that we do not have sufficient information at this time to establish what the health-based emission standards would be for HCl or the other acid gases from EGUs alone, much less for EGUs and other sources of acid gas HAP located at or near facilities with EGUs.

Finally, we considered the fact that setting conventional MACT standards for HCl as well as PM (as a surrogate for HAP metals) would result in significant reductions in emissions of other pollutants, most notably SO[2], PM, and other non-HAP acid gases (*e.g.*, hydrogen bromide) and would likely also result in additional reductions in emissions of Hg and other HAP metals (*e.g.*, Se). The additional reductions of

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[168] Evans, CD, Monteith, DT, Fowler, D, Cape, JN, and Brayshaw, S. *Hydrochloric Acid: an Overlooked Driver of Environmental Change,* Env. Sci. Technol., DOI: 10.1021/es10357u.

SO[2] alone attributable to the proposed limit for HCl are estimated to be 2.1 million tons in the third year following promulgation of the proposed HCl standard. These are substantial reductions with substantial public health benefits. Although NESHAP may directly address only HAP, not criteria pollutants, Congress did recognize, in the legislative history to CAA section 112(d)(4), that NESHAP would have the collateral benefit of controlling criteria pollutants as well and viewed this as an important benefit of the air toxics program. [169] Therefore, even where EPA concludes a HAP has a health threshold, the Agency may consider the collateral benefits of controlling criteria pollutants as a factor in determining whether to exercise its discretion under CAA section 112(d)(4).

Given the limitations of the currently available information (*e.g.*, the HAP mix where EGUs are located, and the cumulative impacts of respiratory irritants from nearby sources), the environmental effects of HCl and the other acid gas HAP, and the significant co-benefits of setting a conventional MACT standard for HCl and the other acid gas HAP, the Administrator is proposing not to exercise her discretion to use CAA section 112(d)(4).

This conclusion is not contrary to EPA's prior decisions noted earlier where we found it appropriate to exercise the discretion to invoke the authority in CAA section 112(d)(4) for HCl, because the circumstances in this case differ from previous considerations. EGUs differ from the other source categories for which EPA has exercised its authority under CAA section 112(d)(4) in ways that affect consideration of any health threshold for HCl. EGUs are much more

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[169] *See* S. Rep. No. 101-228, 101st Cong. 1st sess. At 172.

likely to be significant emitters of acid gas HAP and non-HAP than are other source categories. In fact, they are the largest anthropogenic emitter of HCl and HF in the U.S, emitting roughly half of the estimated nationwide total HCl and HF emissions in 2010. Our case study analyses of the chronic impacts of EGUs did not indicate any significant potential for them to cause any exceedances of the chronic RfC for HCl due to their emissions alone.[170] However, we do not have adequate information on the other acid gas HAP to include them in our analysis, and did not consider their impacts in concert with other emitters of HCl (such as IB units) to develop estimates of cumulative exposures to HCl and other acid gas HAP in the vicinity of EGUs. In addition, EGUs may be located at facilities in heavily populated urban areas where many other sources of HAP exist. These factors make an analysis of the health impact of emissions from these sources on the exposed population significantly more complex than for many other source categories, and, therefore, make it more difficult to establish an ample margin of safety without significantly more information. Absent the information necessary to provide a credible basis for developing alternative health-based emission standards for all acid gases, and for all the other reasons discussed above, EPA is choosing not to exercise its discretion under CAA section 112(d)(4) for these pollutants from EGUs.

K. How did we select the compliance requirements?

We are proposing testing, monitoring, notification, and recordkeeping requirements that are adequate to

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[170] For those facilities modeled, the hazard index for HCl ranged from 0.05 to 0.005 (see Non-Hg Case Study Chronic Inhalation Risk Assessment for the Utility MACT "Appropriate and Necessary" Analysis in the docket).

assure continuous compliance with the requirements of this proposed rule. These requirements are described elsewhere in this preamble. We selected these requirements based upon our determination of the information necessary to ensure that the emission standards and work practices are being followed and that emission control devices and equipment are maintained and operated properly. These proposed requirements ensure compliance with this proposed rule without imposing a significant additional burden for units that must implement them.

We are proposing that units using continuous monitoring systems for PM, HCl, and Hg demonstrate initial compliance by performance testing for non-Hg HAP metals and the surrogate PM, for HCl and its surrogate SO[2], and for Hg, and then to perform subsequent performance testing every 5 years for non-Hg HAP metals and PM and for HCl and SO[2]. To ensure continuous compliance with the proposed Hg emission limits in-between the performance tests, this proposed rule would require coal-fired units to use either CEMS or sorbent trap monitoring systems, with an option for very low emitters to use a less rigorous method based on periodic stack testing. These requirements are found in proposed Appendix A to 40 CFR part 63, subpart UUUUU. For PM and HCl, affected units that elect to install CEMS would use the CEMS to demonstrate continuous compliance. However, units equipped with devices that control PM and HCl emissions but do not elect to use CEMS, would determine suitable parameter operating limits, to monitor those parameters on a continuous basis, and to conduct emissions testing every other month. Units combusting liquid oil on a limited basis would, upon request and approval, be allowed to determine limits for metals, chlorine, and Hg concentrations in fuel and

to measure subsequent fuel metals, chlorine, and Hg concentrations monthly; and low emitting units would be allowed to determine limits for metals, chlorine, and Hg concentrations in fuel and to measure subsequent fuel metals, chlorine, and Hg concentrations monthly.

Additionally, this proposed rule would require annual maintenance be performed so that good combustion continues. Such an annual check will serve to ensure that dioxins, furans, and other organic HAP emissions continue to be at or below MDLs.

We evaluated the feasibility and cost of applying PM CEMS to EGUs. Several electric utility companies in the U.S. have now installed or are planning to install PM CEMS. In recognition of the fact that PM CEMS are commercially available, EPA developed and promulgated PSs for PM CEMS *(69 FR 1786,* January 12, 2004). Performance Specifications for PM CEMS are established under PS 11 in appendix B to 40 CFR part 60 for evaluating the acceptability of a PM CEMS used for determining compliance with the emission standards on a continuous basis. For PM CEMS monitoring, initial costs were estimated to be $ 261,000 per unit and annualized costs were estimated to be $91,000 per unit. We determined that requiring PM CEMS for EGUs combusting coal or oil is a reasonable monitoring option. We are requesting comment on the application of PM CEMS to EGUs, and the use of data from such systems for compliance determinations under this proposed rule.

Table 14 holds preliminary cost information. Note that these costs are based on 2010 ICR emissions test estimates and on values in EPA's monitoring costs assessment tool. Particulate matter and metals and SO[2] and HCl testing includes surrogacy testing

initially and every 5 years, parameter monitoring includes testing every two months, and fuel content monitoring includes annual testing.

Table 14—Cost Information

	Initial costs, $ K	Annual costs, $ K	
Metals			
PM CEMS	261	91	
Fabric filter	61	109	
ESP	59	114	
Acid Gases			
SO[2] CEMS	232	66	None if existing CEMS used.
HCl CEMS	233	57	
Dry sorbent injection	10	144	Plus material costs.
Wet scrubber	9	143	
Mercury			
Hg CEMS	271	110	
Sorbent traps	23	128	Minimum of 52 traps and analysis per year.
Fuel analysis	10	49	
Dioxin/furan and non-dioxin/furan organic HAP			
Tune up	17	3	

The Agency is seeking comment on the cost information presented above. The commenters are encouraged to provide detailed information and data that will help the Agency refine its cost estimates for this rulemaking.

The majority of test methods that this proposed rule would require for the performance stack tests have been required under many other EPA standards. Three applicable voluntary consensus standards were identified: American Society of Mechanical Engineers (ASME) Performance Test Code (PTC) 19-10-1981-Part 10, "Flue and Exhaust Gas Analyses," a manual method for measuring the oxygen, CO[2], and CO content of exhaust gas; ASTM Z65907, "Standard Method for Both Speciated and Elemental Mercury Determination," a method for Hg measurement; and ASTM Method D6784-02 (Ontario Hydro), a method for measuring Hg. The majority of emissions tests upon which the proposed emission limitations are based were conducted using these test methods.

When a performance test is conducted, we are proposing that parameter operating limitations be determined during the tests. Performance tests to demonstrate compliance with any applicable emission limitations are either stack tests or fuel analysis or a combination of both.

To ensure continuous compliance with the proposed emission limitations and/or operating limits, this proposed rule would require continuous parameter monitoring of control devices and recordkeeping. We selected the following requirements based on reasonable cost, ease of execution, and usefulness of the resulting data to both the owners or operators and EPA for ensuring continuous compliance with the emission limitations and/or operating limits.

We are proposing that certain parameters be continuously monitored for the types of control devices commonly used in the industry. These parameters include pH, pressure drop and liquid flow rate for wet scrubbers; and sorbent injection rate for dry scrubbers

and DSI systems. You must also install a BLDS for FFs. These monitoring parameters have been used in other standards for similar industries. The values of these parameters are established during the initial or most recent performance test that demonstrates compliance. These values are your operating limits for the control device.

You would be required to set parameters based on 4-hour block averages during the compliance test, and demonstrate continuous compliance by monitoring 12-hour block average values for most parameters. We selected this averaging period to reflect operating conditions during the performance test to ensure the control system is continuously operating at the same or better level as during a performance test demonstrating compliance with the emission limits.

To demonstrate continuous compliance with the emission and operating limits, you would also need daily records of the quantity, type, and origin of each fuel burned and hours of operation of the affected source. If you are complying with the chlorine fuel input option, you must keep records of the calculations supporting your determination of the chlorine content in the fuel.

If a liquid oil-fired EGU elected to demonstrate compliance with the HCl or individual or total HAP metal limit by using fuel which has a statistically lower pollutant content than the emission limit, we are proposing that the source's operating limit is the emission limit of the applicable pollutant. Under this option, a source is not required to conduct performance stack tests. If a source demonstrates compliance with the HCl, individual or total PM, or Hg limit by using fuel with a statistically higher pollutant content than the applicable emission limit, but performance tests

demonstrate that the source can meet the emission limitations, then the source's operating limits are the operating limits of the control device (if used) and the fuel pollutant content of the fuel type/mixture burned.

This proposed rule would specify the testing methodology and procedures and the initial and continuous compliance requirements to be used when complying with the fuel analysis options. Fuel analysis tests for total chloride, gross calorific value, Hg, individual and total HAP metal, sample collection, and sample preparation are included in this proposed rule.

If you are a liquid oil-fired EGU and elect to comply based on fuel analysis, you will be required to statistically analyze, using the z-test, the data to determine the 90th percentile confidence level. It is the 90th percentile confidence level that is required to be used to determine compliance with the applicable emission limit. The statistical approach is required to assist in ensuring continuous compliance by statistically accounting for the inherent variability in the fuel type.

We are proposing that a source be required to recalculate the fuel pollutant content only if it burns a new fuel type or fuel mixture and conduct another performance test if the results of recalculating the fuel pollutant content are higher than the level established during the initial performance test.

L. What alternative compliance provisions are being proposed?

We are proposing that owners and operators of existing affected sources may demonstrate compliance by emissions averaging for units at the affected source that are within a single subcategory.

As part of EPA's general policy of encouraging the use of flexible compliance approaches where they can be properly monitored and enforced, we are including emissions averaging in this proposed rule. Emissions averaging can provide sources the flexibility to comply in the least costly manner while still maintaining regulation that is workable and enforceable. Emissions averaging would not be applicable to new affected sources and could only be used between EGUs in the same subcategory at a particular affected source. Also, owners or operators of existing sources subject to the EGU NSPS (40 CFR part 60, subparts D and Da) would be required to continue to meet the PM emission standard of that NSPS regardless of whether or not they are using emissions averaging.

Emissions averaging would allow owners and operators of an affected source to demonstrate that the source complies with the proposed emission limits by averaging the emissions from an individual affected unit that is emitting above the proposed emission limits with other affected units at the same facility that are emitting below the proposed emission limits and that are within the same subcategory.

This proposed rule includes an emissions averaging compliance alternative because emissions averaging represents an equivalent, more flexible, and less costly alternative to controlling certain emission points to MACT levels. We have concluded that a limited form of averaging could be implemented that would not lessen the stringency of the MACT floor limits and would provide flexibility in compliance, cost and energy savings to owners and operators. We also recognize that we must ensure that any emissions averaging option can be implemented and enforced, will be clear to sources, and most importantly, will be

no less stringent than unit by unit implementation of the MACT floor limits.

EPA has concluded that it is permissible to establish within a NESHAP a unified compliance regimen that permits averaging within an affected source across individual affected units subject to the standard under certain conditions. Averaging across affected units is permitted only if it can be demonstrated that the total quantity of any particular HAP that may be emitted by that portion of a contiguous major source that is subject to the NESHAP will not be greater under the averaging mechanism than it could be if each individual affected unit complied separately with the applicable standard. Under this test, the practical outcome of averaging is equivalent to compliance with the MACT floor limits by each discrete unit, and the statutory requirement that the MACT standard reflect the maximum achievable emissions reductions is, therefore, fully effectuated.

In past rulemakings, EPA has generally imposed certain limits on the scope and nature of emissions averaging programs. These limits include: (1) No averaging between different types of pollutants; (2) no averaging between sources that are not part of the same affected source; (3) no averaging between individual sources within a single major source if the individual sources are not subject to the same NESHAP; and (4) no averaging between existing sources and new sources.

This proposed rule would fully satisfy each of these criteria. First, emissions averaging would only be permitted between individual sources at a single existing affected source, and would only be permitted between individual sources subject to the proposed EGU NESHAP. Further, emissions averaging would

not be permitted between two or more different affected sources. Finally, new affected sources could not use emissions averaging. Accordingly, we have concluded that the averaging of emissions across affected units is consistent with the CAA. In addition, this proposed rule would require each facility that intends to utilize emission averaging to submit an emission averaging plan, which provides additional assurance that the necessary criteria will be followed. In this emission averaging plan, the facility must include the identification of: (1) All units in the averaging group; (2) the control technology installed; (3) the process parameter that will be monitored; (4) the specific control technology or pollution prevention measure to be used; (5) the test plan for the measurement of the HAP being averaged; and (6) the operating parameters to be monitored for each control device. Upon receipt, the regulatory authority would not be able to approve an emission averaging plan containing averaging between emissions of different types of pollutants or between sources in different subcategories.

This proposed rule would also exclude new affected sources from the emissions averaging provision. EPA believes emissions averaging is not appropriate for new affected sources because it is most cost effective to integrate state-of-the-art controls into equipment design and to install the technology during construction of new sources. One reason we allow emissions averaging is to give existing sources flexibility to achieve compliance at diverse points with varying degrees of add-on control already in place in the most cost-effective and technically reasonable fashion. This flexibility is not needed for new affected sources because they can be designed and constructed with compliance in mind.

In addition, we seek comment on use of a discount factor when emissions averaging is used and on the appropriate value of a discount factor, if used. Such discount factors (*e.g.*, 10 percent) have been used in previous NESHAP, particularly where there was variation in the types of units within a common source category to ensure that the environmental benefit was being achieved. In this situation, however, the affected sources are more homogeneous, making emissions averaging a more straight-forward analysis. Further, with the monitoring and compliance provisions that are being proposed, there is additional assurance that the environmental benefit will be realized. Further, the emissions averaging provision would not apply to individual units if the unit shares a common stack with units in other subcategories, because in that circumstance it is not possible to distinguish the emissions from each individual unit.

The emissions averaging provisions in this proposed rule are based in part on the emissions averaging provisions in the Hazardous Organic NESHAP (HON). The legal basis and rationale for the HON emissions averaging provisions were provided in the preamble to the final HON.[171]

M. How did EPA determine compliance times for this proposed rule?

CAA section 112 specifies the dates by which affected sources must comply with the emission standards. New or reconstructed units must be in compliance with this proposed rule immediately upon startup or [DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER], whichever is later.

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[171] Hazardous Organic NESHAP *(59 FR 19425;* April 22, 1994).

Existing sources may be provided up to 3 years to comply with the final rule; if an existing source is unable to comply within 3 years, a permitting authority has the discretion to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls. *See* section 112(i)(3). We believe that 3 years for compliance is necessary to allow adequate time to design, install and test control systems that will be retrofitted onto existing EGUs, as well as obtain permits for the use of add-on controls.

We believe that the requirements of the proposed rule can be met without adversely impacting electric reliability. Our analysis shows that the expected number of retirements is less than many have predicted and that these can be managed effectively with existing tools and processes for ensuring continued grid reliability. Further, the industry has adequate resources to install the necessary controls and develop the modest new capacity required within the compliance schedule provided for in the CAA. Although there are a significant number of controls that need to be installed, with proper planning, we believe that the compliance schedule established by the CAA can be met. There are already tools in place (such as integrated resource planning, and in some cases, advanced auctions for capacity) that ensure that companies adequately plan for, and markets are responsive to, future requirements such as the proposed rule. In addition, EPA itself has already begun reaching out to key stakeholders including not only sources with direct compliance obligations, but also groups with responsibility to assure an affordable and reliable supply of electricity including state Public Utility Commissions (PUC), Regional Transmission

Organizations (RTOs), the National Electric Reliability Council (NERC), the Federal Energy Regulatory Commission (FERC), and DOE. EPA intends to continue these efforts during both the development and implementation of this proposed rule. It is EPA's understanding that FERC and DOE will work with entities whose responsibility is to ensure an affordable, reliable supply of electricity, including state PUCs, RTOs, the NERC to share information and encourage them to begin planning for compliance and reliability as early as possible. This effort to identify and respond to any projected local and regional reliability concerns will inform decisions about the timing of retirements and other compliance strategies to ensure energy reliability. EPA believes that the ability of permitting authorities to provide an additional 1 year beyond the 3-year compliance timeframe as specified in CAA section 112, along with other compliance tools, ensures that the emission reductions and health benefits required by the CAA can be achieved while safeguarding completely against any risk of adverse impacts on electricity system reliability. Between proposal and final, EPA will work with DOE and FERC to identify any opportunities offered by the authorities and policy tools at the disposal of DOE and/or FERC that can be pursued to further ensure that the dual goals of substantially reducing the adverse public health impacts of power generation, as required by the CAA, while continuing to assure electric reliability is maintained. EPA also intends to continue to work with DOE, FERC, state PUCs, RTOs and power companies as this rule is implemented to identify and address any challenges to ensuring that both the requirements of the CAA and the need for a reliable electric system are met.

In developing this proposed rule, EPA has performed specific analysis to assess the feasibility (*e.g.*, ability of companies to install the required controls within the compliance time-frame) and potential impact of the proposed rule on reliability.

With regards to feasibility, EPA used IPM to project what types of controls would need to be installed to meet the requirements of this proposed rule. This includes technologies to control acid gases (wet and dry scrubber technology and the use of sorbent injection), the Hg requirements (co-benefits from other controls such as scrubbers and FFs and Hg-specific controls such as ACI), the non-Hg metal requirements (upgrades and or replacements of existing particulate control devices), and other HAP emissions (GCP).

Much of the power sector already has controls in place that remove significant amounts of acid gases. Today over 50 percent of the power generation fleet has scrubbing technology installed and the industry is already working on installations to bring that number to nearly two-thirds of the fleet by 2015. Many of the remaining coal-fired units are smaller, burn lower sulfur coals, and/or do not operate in a base-load mode. Units with these types of characteristics are candidates to use DSI technology which takes significantly less time to install. Units that choose to install dry or wet scrubbing technology should be able to do so within the compliance schedule required by the CAA as this technology can be installed within the 3-year window.[172] Notably, EPA does not project use

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[172] In a letter to Senator Carper dated November 3, 2010 (*http://www.icac.com/files/public/ICAC_Carper_Response_110310.pdf*) David Foerter, the executive director of the Institute of Clean Air Companies (ICAC) explained that wet scrubber technology could be installed in 36 months, dry scrubber

of wet scrubbing technology to meet the requirements of this proposed rule and that is the technology that typically takes a longer time to install.

For Hg control, those units that do not meet the requirements with existing controls have several options. Companies with installed scrubbers may be able to make modifications (such as the use of scrubber additives to enhance Hg control). Other companies may use supplemental controls such as ACI. These types of options all take significantly less than 3 years to install.

Units that do not meet the non-Hg metal HAP requirements have several options such as upgrading existing particulate controls, installing supplemental particulate controls, or replacing existing particulate controls. These options can also be implemented in significantly less than 3 years.

EPA projects that for acid gas control, companies will likely use dry scrubbing and sorbent injection technologies rather than wet scrubbing. For non-Hg metal HAP controls, EPA has assumed that companies with ESPs will likely upgrade them to FFs. As a number of units that were in the MACT floor for non-Hg HAP metals only had ESPs installed, this is likely a conservative assumption. For Hg, EPA projects that companies will comply through either the collateral reductions created by other controls (*e.g.*, scrubber/SCR combination) or ACI. EPA has assessed the feasibility of installing these controls within the compliance window (see TSD) and believes that the controls can be reasonably installed within that time. Although EPA assessed the ability to install the

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technology could be installed in 24 months and dry sorbent injection could be installed in 12 months. Page 3.

controls in 3 years (and determined that the controls could be installed in that time-frame), this would require the control technology industry to ramp up quickly. Therefore, EPA also assessed a time-frame that would allow some installations to take up to 4 years. This time-frame is consistent with the CAA which allows permitting authorities the discretion to grant extensions to the compliance time-line of up to 1 year. This time-frame also allows for staggered installation of controls at facilities that need to install technologies on multiple units. Staggered installation allows companies to address such issues as scheduling outages at different units so that reliable power can be provided during these outage periods or particularly complex retrofits (*e.g.*, when controls for one unit need to be located in an open area needed to construct controls on another unit). In other words, the additional 1-year extension would provide an additional two shoulder periods to schedule outages. It also provides additional opportunity to spread complex outages over multiple outage periods. EPA believes that while many units will be able to fully comply within 3 years, the 4th year that permitting authorities are allowed to grant for installation of controls is an important flexibility that will address situations where an extra year is necessary.

Permitting authorities are familiar with the operation of this provision because they have used it in implementing previous NESHAP. This extension can be used to address a range of reasons that installation schedules may take more than 3 years including: staggering installations for reliability or constructability purposes, or other site-specific challenges that may arise related to source-specific construction issues, permitting, or local manpower or resource challenges. EPA is proposing that States

consider applying this extension both to the installation of add on controls (*e.g.*, a FF, or a dry scrubber) and the construction of on-site replacement power (*e.g.*, a case when a coal unit is being shut down and the capacity is being replaced on-site by another cleaner unit such as a combined cycle or simple cycle gas turbine and the replacement process requires more than 3 years to accomplish). EPA believes that it is reasonable to allow the extension to apply to the replacement because EPA believes that building of replacement power could be considered "installation of controls" at the facility. Because the phrase "installation of controls" could also be interpreted to apply only to changes made to an existing unit rather than the replacement of that existing unit with a new cleaner one, EPA takes comment on its proposal to allow the extension to apply to replacement power.

EPA has also considered the impact that potential retirements under this proposed rule will have on reliability. When considering the impact that one specific action has on power plant retirements, it is important to understand that the economics that drive retirements are based on multiple factors including: Expected electric demand, cost of alternative generation, and cost of continuing to generate using an existing unit. EPA's analysis shows that the lower cost of alternative generating sources (particularly the cost of natural gas), as well as reductions in demand, have a greater impact on the number of projected retirements than does the impact of the proposed rule. EPA's assessment looked at the reserve margins in each of 32 subregions in the continental U.S. It shows that with the addition of very little new capacity, average reserve margins are significantly higher than required (NERC assumes a default reserve margin of 15 percent while the average capacity margin seen

after implementation of the policy is nearly 25 percent). Although such an analysis does not address the potential for more localized transmission constraints, the number of retirements projected suggests that the magnitude of any local retirements should be manageable with existing tools and processes. Demand forecasts used were based on EIA projected demand growth.

Reliability concerns caused by local transmission constraints can be addressed through a range of solutions including the development of new generation and/or demand side resources, and/or enhancements to the transmission system. On the supply side, there are a range of options including the development of more centralized power resources (either base-load or peaking), and/or the development of cogeneration, or distributed generation. Even with the large reserve margins, there are companies ready to implement supply side projects quickly. For instance, in the PJM Interconnection (an RTO) region, there are over 11,600 MW of capacity that have completed feasibility and impact studies and could be on-line by the third quarter of 2014.[173] Demand side options include energy efficiency as well as demand response programs. These types of resources can also be developed very quickly. In 2006, PJM Interconnection had less than 2,000 MWs of capacity in demand side resources. Within 4 years this capacity nearly quadrupled to

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[173] Paul M Sotkiewicz, PJM Interconnection, Presentation at the Bipartisan Policy Commission Workshop Series on Environmental Regulation and Electric System Reliability, Workshop 3: Local, State, Regional and Federal Solutions, January 19, 2011, Washington DC, http://www.bipartisanpolicy.org/sites/default/files/Paul%20Sotkiewicz-%20Panel%202_0.pdf, slide 6.

almost 8,000 MW of capacity.[174] Recent experience also shows that transmission upgrades to address reliability issues from plant closures can also occur in less than 3 years. In addition to helping address reliability concerns, reducing demand through mechanisms such as energy efficiency and demand side management practices has many other benefits. It can reduce the cost of compliance and has collateral air quality benefits by reducing emissions in periods where there are peak air quality concerns.

EPA also examined the impact on reliability of unit outages to install control equipment. Because these outages usually occur in the shoulder months (outside summer or winter peaking periods) when demand is lower (and, thus, reserve margins are higher), the analysis showed that even with conservative estimates regarding the length of the outages and conservative estimates about how many outages occurred within a 1-year time-frame, reserve margins were maintained. With the potential for a 1-year compliance extension, outages can be further staggered, providing additional flexibility, even if some units require longer outages.

Although EPA's analysis shows that there is sufficient time and grid capacity to allow for compliance with the rule within the 3-year compliance window (with the possibility of a 1-year extension), to achieve compliance in a timely fashion, EPA expects that sources will begin promptly, based upon this proposed rule, to evaluate, select, and plan to implement, source-specific compliance options. In doing so, we would expect sources to consider the

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[174] Ibid—slide 5.

following factors: if retirement is the selected compliance option, notifying any relevant RTO/ISO in advance in order to develop an appropriate shutdown plan that identifies any necessary replacement power transmission upgrades or other actions necessary to ensure consistent electric supply to the grid; if installation of control technologies is necessary, any source-specific space limitations, such that installation can be staggered in a timely fashion; and source-specific electric supply requirements, such that outages can be appropriately scheduled. Starting assessments early and considering the full range of options is prudent because it will help ensure that the requirements of this proposed rule are met as economically as possible and that power companies are able to provide reliable electric power.

There is significant evidence that companies do in fact engage in such forward planning. For instance, in September of 2004 (approximately 6 months before the CAIR and CAMR requirements were finalized); Cinergy announced that it had already begun a construction program to comply. This program involved not only preliminary engineering, but actual construction of scrubbers.[175] Southern Company also began its engineering process well before those rules were finalized.[176] Although EPA understands that not every generating company may commit to actual capital projects in advance of finalization of the rule, the CAIR experience shows that some companies do. Even if companies do not take the step of committing

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[175] Cinergy Press Release, September 2nd, 2004, "Cinergy Operating Companies to Reduce Power Plant Emissions, Improve Air Quality."

[176] ICAC.

to the capital projects, there are actions that companies can take that are much less costly. Companies can analyze their unit-by-unit compliance options based on the proposed rule. This will put them in a position to begin construction of projects with the longest lead times quickly and will ensure that the 3-year compliance window (or 4 with extension from the permitting authority) can be met.

It will also ensure that sufficient notification can be provided to RTOs/ISOs so that the full range of options for addressing any reliability concerns can be considered. Although most RTOs/ISOs only require 90-day notifications for retirements, construction schedules for all but the simplest retrofits will be longer, so sources should be able to notify their RTOs of their retirements earlier. This will also help as multiple sources work with their RTO/ISO to determine outage schedules. The RTOs/ISOs also have a very important role to play and it appears that a number of them are already engaged in preparing for these rules. For instance, PJM Interconnection considered the impact of these anticipated rules at its January 14, 2011, Regional Planning Process Task Force Meeting,[177] and Midwest Independent Transmission System Operator, Inc. (MISO) has also begun a planning process to consider the impact of EPA rules.[178]

As discussed above, given the large reserve margins that exist, even after consideration of requirements of the proposed rule, EPA believes that any reliability issues are likely to be primarily local in nature and be

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[177] Paul M Sotkiewicz, PJM Interconnection, "Consideration of Forthcoming Environmental Regulations in the Planning Process," January 14, 2011.

[178] MISO Planning Advisory Committee, "Proposed EPA Regulatory Impact Analysis," November 23, 2010.

due to the retirement of a unit in a load constrained area. As demonstrated by the work that PJM Interconnection and MISO are doing, RTOs/ISOs are required to do long range (at least 10 years) capacity planning that includes consideration of future requirements such as EPA regulations. Furthermore, if companies within an RTO/ISO wish to retire a unit, they must first notify the RTO/ISO in advance so that any reliability concerns can be addressed. The RTOs/ISOs, have well established procedures to address such retirements.

Starting assessments early and considering the full range of options will help ensure that the requirements of this rule are met as economically as possible and that power companies are able to provide reliable electric power while significantly reducing their impact on public health. For power companies this includes considering the range of pollution control options available for their existing fleet as well as considering the range of options for replacement power, in the cases where shutting down a unit is the more economic choice. The RTOs/ISOs should consider the full range of options to provide any necessary replacement power including the development of both supply and demand side resources. Environmental regulators should work with their affected sources early to understand their compliance choices. In this way, those regulators will be able to accurately access when use of the 1-year compliance extension is appropriate. By working with regulators early, affected sources will be in a position to have assurance that the 1-year extension will be granted in those situations where it is appropriate.

Section X.c. describes the sensitivity analysis performed by EPA for an Energy Efficiency case, in

which a combination of DOE appliance standards and State investments in demand-side efficiency come into place at the same time as compliance with the requirements of this rule. That analysis shows that even in the absence of this rule, moderate actions to promote energy efficiency would lead to retirement of an additional 11 GW in 2015, of 27 GW in 2020, and of 26 GW in 2030, beyond the capacity already projected to retire in the base case. In effect, the timely adoption and implementation of energy efficiency policies would augment currently projected reserve capacities that are instrumental to assuring system reliability.

As noted, instrumental to undertaking such actions are other Federal agencies such as DOE, ISOs and RTOs, and state agencies such as PUCs. Fortunately, in addition to helping to assure system reliability, timely implementation of energy efficiency policies offer these key decision-makers an additional incentive to take action. As the analysis shows, energy efficiency can reduce costs for ratepayers and customers.

First, with or without the proposed Toxic Rule, energy efficiency policies are shown by the analysis to reduce the overall costs of generating electricity, with the cost reductions increasing over time. *See* Table 22. Second, when comparing the Toxics Rule Case without energy efficiency to the Toxics Rule Case with energy efficiency, the analysis suggests that if these energy efficiency policies were to be put into place and maintained over time by system operators, states and DOE, the costs of the proposed Toxics Rule are mitigated by these cost reductions such that the overall system costs are reduced by $ 2 billion in 2015, $ 6 billion in 2020, and $ 11 billion in 2030.

The energy savings driven by these energy efficiency policies mean that consumers will pay less for electricity as well. EPA has modeled national average retail electricity prices, including the energy efficiency costs that are paid by the ratepayer. The Toxics Rule increases retail prices by 3.7 percent, 2.6 percent and 1.9 percent in 2015, 2020 and 2030 respectively relative to the base case. If energy efficiency policies are implemented along with the Toxics Rule, the average retail price of electricity increases by 3.3 percent in 2015 relative to the base case, but falls relative to the base case by about 1.6 percent in 2020 and about 2.3 percent in 2030. The effect on electricity bills however may fall more than these percentages suggest as energy efficiency means that less electricity will be used by consumers of electricity.

EPA believes that as it shares these results with PUCs, the commissions will respond in accordance with their ongoing imperative to ensure that electricity costs for ratepayers and consumers remains stable. Specifically, the opportunity created through the deployment of energy efficiency-promoting strategies and initiatives to safeguard system reliability and, especially, to curb cost increases that might otherwise result from implementation of the Toxics Rule should provide PUCs with both the motivation and the justification for providing utilities with the financial and regulatory support they need to begin planning as early as possible for compliance and to incorporate in their plans the kinds of energy efficiency investments needed to achieve both compliance and cost-minimization.

EPA recognizes that both utilities and their regulators often are hesitant to take early action to comply with environmental standards because they avoid

incurring costs that they fear may not be required once the final regulation is promulgated. EPA urges utilities and regulators to begin planning and preparations for timely compliance. The same concerns about consumer cost in some cases also dissuade utilities from incurring, and commissions from authorizing, the upfront costs associated with energy efficiency programs. However, EPA also believes that if it takes steps to actively disseminate the results of the energy efficiency analysis, then utilities will be that much more likely to begin, and regulators that much more likely to support, comprehensive assessment and planning as early as possible since compliance approaches that encompass energy efficiency integrated with other actions needed to meet the Toxics Rule's requirements will result in lower costs for ratepayers and consumers. EPA encourages State environmental regulators to consider the extent to which a utility engages in early planning when making a decision regarding granting a 4th year for compliance with the Toxics Rule.

In summary, EPA believes that the large reserve margins, the range of control options, the range of flexibilities to address unit shutdowns, existing processes to assure that sufficient generation exists when and where it is needed, and the flexibilities within the CAA, provide sufficient assurance that the CAA section 112 requirements for the power sector can be met without adversely impacting electric reliability.

EGUs are the subject of several rulemaking efforts that either are or will soon be underway. In addition to this rulemaking proposal, concerning both hazardous air pollutants under section 112 and criteria pollutant NSPS standards under section 111, EGUs

are the subject of other rulemakings, including ones under section 110(a)(2)(D) addressing the interstate transport of emissions contributing to ozone and PM air quality problems, coal combustion wastes, and the implementation of section 316(b) of the Clean Water Act (CWA). They will also soon be the subject of a rulemaking under CAA section 111 concerning emissions of greenhouse gases.

EPA recognizes that it is important that each and all of these efforts achieve their intended environmental objectives in a common-sense manner that allows the industry to comply with its obligations under these rules as efficiently as possible and to do so by making coordinated investment decisions and, to the greatest extent possible, by adopting integrated compliance strategies. In addition, EO 13563 states that "[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote such coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation." Thus, EPA recognizes that it needs to approach these rulemakings, to the extent that its legal obligations permit, in ways that allow the industry to make practical investment decisions that minimize costs in complying with all of the final rules, while still achieving the fundamentally important environmental and public health benefits that the rulemakings must achieve.

The upcoming rulemaking under section 111 regarding GHG emissions from EGUs may provide an opportunity to facilitate the industry's undertaking integrated compliance strategies in meeting the requirements of these rulemakings. First, since that

rulemaking will be finalized after a number of the other rulemakings that are currently underway are, the Agency will have an opportunity to take into account the effects of the earlier rulemakings in making decisions regarding potential GHG standards for EGUs.

Second, in that rulemaking, EPA will be addressing both CAA section 111(b) standards for emissions from new and modified EGUs and CAA section 111(d) emission guidelines for states to follow in establishing their plans regarding GHG emissions from existing EGUs. In evaluating potential emission standards and guidelines, EPA may consider the impacts of other rulemakings on both emissions of GHGs from EGUs and the costs borne by EGUs. The Agency expects to have ample latitude to set requirements and guidelines in ways that can support the states' and industry's efforts in pursuing practical, cost-effective and coordinated compliance strategies encompassing a broad suite of its pollution-control obligations. EPA will be taking public comment on such flexibilities in the context of that rulemaking.

As discussed elsewhere in this preamble, we invite comment on this proposed rule. EPA solicits comment on the ability of sources subject to this proposed rule to comply within the statutorily mandated 3-year compliance window and/or the 1-year discretionary extension, as well as comment on specific factors that could prevent a source from achieving, or could enable a source to achieve, compliance. In addition, EPA requests comment on the impact of this proposed rule on electric reliability, and ways to ensure compliance while maintaining the reliability of the grid.

A number of states (or localities) have proactively developed plans to address a suite of environmental

issues, an aging generation fleet, and electric reliability (*e.g.*, plans requiring retirement of coal and pollution control devices such as the Colorado "Clean Air-Clean Jobs Act" or renewable portfolio standards that because of the states' current generation mix could result in significant changes to the composition of the fossil-fuel-fired portion of the fleet such as Hawaii's renewable portfolio standard (HB-1464)). In most cases, these plans were developed solely under State law with no underlying Federal requirement. Furthermore, as explained above, many of the technologies that were installed or that are planned to be installed in response to these state plans are likely to result in collateral reductions of many HAP required to be reduced in today's proposed rule. Although some of these state programs may have obtained some important emission reductions to date, they may also allow compliance time-frames for some units that extend beyond those authorized under CAA section 112(i)(3).

The Agency has a program pursuant to 40 CFR subpart E, whereby states can take delegation of section 112 emission standards. Among other things, states can seek approval of state rules to the extent they can demonstrate that those rules are no less stringent that the applicable section 112(d) rule. Because overall, some of these state programs may result in greater emission reductions, EPA is taking comment on whether (and if so how) such state plans could be integrated with the proposed rule requirements consistent with the statute. EPA also intends to engage with states who believe that they have such plans to understand whether they believe that there are opportunities to integrate the two sets of requirements in a manner consistent with the requirements of the CAA.

EGUs are the subject of several rulemaking efforts that either are or will soon be underway. In addition to this rulemaking proposal, concerning both HAP under section 112 and criteria pollutant NSPS standards under section 111, EGUs are the subject of other rulemakings, including ones under section 110(a)(2)(D) addressing the interstate transport of emissions contributing to ozone and PM air quality problems, coal combustion wastes, and the implementation of section 316(b) of the CWA. They will also soon be the subject of a rulemaking under CAA section 111 concerning emissions of greenhouse gases (GHG).

EPA recognizes that it is important that each and all of these efforts achieve their intended environmental objectives in a common-sense manner that allows the industry to comply with its obligations under these rules as efficiently as possible and to do so by making coordinated investment decisions and, to the greatest extent possible, by adopting integrated compliance strategies. Thus, EPA recognizes that it needs to approach these rulemakings, to the extent that its legal obligations permit, in ways that allow the industry to make practical investment decisions that minimize costs in complying with all of the final rules, while still achieving the fundamentally important environmental and public health benefits that the rulemakings must achieve.

The upcoming rulemaking under section 111 regarding GHG emissions from EGUs may provide an opportunity to facilitate the industry's undertaking integrated compliance strategies in meeting the requirements of these rulemakings. First, since that rulemaking will be finalized after a number of the other rulemakings that are currently underway are, the agency will have an opportunity to take into

account the effects of the earlier rulemakings in making decisions regarding potential GHG standards for EGUs.

Second, in that rulemaking, EPA will be addressing both CAA section 111(b) standards for emissions from new and modified EGUs and CAA section 111(d) emission guidelines for states to follow in establishing their plans regarding GHG emissions from existing EGUs. In evaluating potential emission standards and guidelines, EPA may consider the impacts of other rulemakings on both emissions of GHGs from EGUs and the costs borne by EGUs. The Agency expects to have ample latitude to set requirements and guidelines in ways that can support the states' and industry's efforts in pursuing practical, cost-effective and coordinated compliance strategies encompassing a broad suite of its pollution-control obligations. EPA will be taking public comment on such flexibilities in the context of that rulemaking.

N. How did EPA determine the required records and reports for this proposed rule?

You would be required to comply with the applicable requirements in the NESHAP General Provisions, subpart A of 40 CFR part 63, as described in Table 10 of the proposed 40 CFR part 63, subpart UUUUU. We evaluated the General Provisions requirements and included those we determined to be the minimum notification, recordkeeping, and reporting requirements necessary to ensure compliance with, and effective enforcement of, this proposed rule.

We would require additional recordkeeping if you chose to comply with the chlorine or Hg fuel input option. You would need to keep records of the

calculations and supporting information used to develop the chlorine or Hg fuel input operating limit.

O. How does this proposed rule affect permits?

The CAA requires that sources subject to this proposed rule be operated pursuant to a permit issued under EPA-approved state operating permit program. The operating permit programs are developed under Title V of the CAA and the implementing regulations under 40 CFR parts 70 and 71. If you are operating in the first 2 years of the current term of your operating permit, you will need to obtain a revised permit to incorporate this proposed rule. If you are in the last 3 years of the current term of your operating permit, you will need to incorporate this proposed rule into the next renewal of your permit.

P. Alternative Standard for Consideration

As discussed above, we are proposing alternate equivalent emission standards (for certain subcategories) to the proposed surrogate standards in three areas: SO[2] (in addition to HCl), individual non-Hg metals (for PM), and total non-Hg metals (for PM). The proposed emission limitations are provided in Tables 16 and 17 of this preamble.

Table 15—Alternate Emission Limitations for Existing Coal- and Oil-Fired EGUs

Subcategory	Coal-fired unit designed for coal >/= 8,300 Btu/lb	Coal-fired unit designed for coal < 8,300 Btu/lb	IGCC, lb/TBtu (lb/GWh)	Liquid oil, lb/TBtu (lb/GWh)	Solid oil-derived
SO[2]	0.20 lb/MMBtu (2.0 lb/MWh)	0.20 lb/MMBtu (2.0 lb/MWh)	NA	NA	0.40 lb/MMBtu (5.0 lb/MWh).
Total non-Hg metals	0.000040 lb/MMBtu (0.00040 lb/MWh)	0.000040 lb/MMBtu (0.00040 lb/MWh)	5.0 (0.050)	NA	0.000050 lb/MMBtu (0.001 lb/MWh).
Antimony, Sb	0.60 lb/TBtu (0.0060 lb/GWh)	0.60 lb/TBtu (0.0060 lb/GWh)	0.40 (0.0040)	0.20 (0.0030)	0.40 lb/TBtu (0.0070 lb/GWh).
Arsenic, As	2.0 lb/TBtu (0.020 lb/GWh)	2.0 lb/TBtu (0.020 lb/GWh)	2.0 (0.020)	0.60 (0.0070)	0.40 lb/TBtu (0.0040 lb/GWh).
Beryllium, Be	0.20 lb/TBtu (0.0020 lb/GWh)	0.20 lb/TBtu (0.0020 lb/GWh)	0.030 (0.0030)	0.060 (0.00070)	0.070 lb/TBtu (0.00070 lb/GWh).
Cadmium, Cd	0.30 lb/TBtu (0.0030	0.30 lb/TBtu (0.0030	0.20 (0.0020)	0.10 (0.0020)	0.40 lb/TBtu (0.0040

Table 15—Alternate Emission Limitations for Existing Coal- and Oil-Fired EGUs

Subcategory	Coal-fired unit designed for coal >/= 8,300 Btu/lb lb/GWh)	Coal-fired unit designed for coal < 8,300 Btu/lb lb/GWh)	IGCC, lb/TBtu (lb/GWh)	Liquid oil, lb/TBtu (lb/GWh)	Solid oil-derived lb/GWh).
Chromium, Cr	3.0 lb/TBtu (0.030 lb/GWh)	3.0 lb/TBtu (0.030 lb/GWh)	3.0 (0.020)	2.0 (0.020)	2.0 lb/TBtu (0.020 lb/GWh).
Cobalt, Co	0.80 lb/TBtu (0.0080 lb/GWh)	0.80 lb/TBtu (0.0080 lb/GWh)	2.0 (0.0040)	3.0 (0.020)	2.0 lb/TBtu (0.020 lb/GWh).
Lead, Pb	2.0 lb/TBtu (0.020 lb/GWh)	2.0 lb/TBtu (0.020 lb/GWh)	0.0002 lb/MMBtu (0.003 lb/MWh)	2.0 (0.030)	11.0 lb/TBtu (0.020 lb/GWh).
Manganese, Mn	5.0 lb/TBtu (0.050 lb/GWh	5.0 lb/TBtu (0.050 lb/GWh	3.0 (0.020)	5.0 (0.060)	3.0 lb/TBtu (0.040 lb/GWh).
Mercury, Hg	NA	NA	NA	0.050 lb/TBtu (0.0007 0 lb/GWh)	NA.
Nickel, Ni	4.0 lb/TBtu (0.040 lb/GWh)	4.0 lb/TBtu (0.040 lb/GWh)	5.0 (0.050)	8.0 (0.080)	9.0 lb/TBtu (0.090 lb/GWh).

Table 15—Alternate Emission Limitations for Existing Coal- and Oil-Fired EGUs

Subcategory	Coal-fired unit designed for coal >/= 8,300 Btu/lb	Coal-fired unit designed for coal < 8,300 Btu/lb	IGCC, lb/TBtu (lb/GWh)	Liquid oil, lb/TBtu (lb/GWh)	Solid oil-derived
Selenium, Se	6.0 lb/TBtu (0.060 lb/GWh)	6.0 lb/TBtu (0.060 lb/GWh)	22.0 (0.20)	2.0 (0.020)	2.0 lb/TBtu (0.020 lb/GWh).

NA = Not applicable.

Table 16—Alternate Emission Limitations for New Coal- and Oil-Fired EGUs

Subcategory	Coal-fired unit designed for coal >/= 8,300 Btu/lb	Coal-fired unit designed for coal < 8,300 Btu/lb	IGCC *	Liquid oil, lb/GWh	Solid oil-derived
SO[2]	0.40 lb/MWh	0.40 lb/MWh	0.40 lb/MWh	NA	0.40 lb/MWh.
Total metals	0.000040 lb/MWh	0.000040 lb/MWh	0.000040 lb/MWh	NA	0.00020 lb/MWh.
Antimony, Sb	0.000080 lb/GWh	0.000080 lb/GWh	0.000080 lb/GWh	0.0020	0.00090 lb/GWh.
Arsenic, As	0.00020 lb/GWh	0.00020 lb/GWh	0.00020 lb/GWh	0.0020	0.0020 lb/GWh.

Table 16—Alternate Emission Limitations for New Coal- and Oil-Fired EGUs

Subcategory	Coal-fired unit designed for coal >/= 8,300 Btu/lb	Coal-fired unit designed for coal < 8,300 Btu/lb	IGCC *	Liquid oil, lb/GWh	Solid oil-derived
Beryllium, Be	0.000030 lb/GWh	0.000030 lb/GWh	0.000030 lb/GWh	0.00070	0.000080 lb/GWh.
Cadmium, Cd	0.00040 lb/GWh	0.00040 lb/GWh	0.00040 lb/GWh	0.00040	0.0070 lb/GWh.
Chromium, Cr	0.020 lb/GWh	0.020 lb/GWh	0.020 lb/GWh	0.020	0.0060 lb/GWh.
Cobalt, Co	0.00080 lb/GWh	0.00080 lb/GWh	0.00080 lb/GWh	0.0060	0.0020 lb/GWh.
Lead, Pb	0.00090 lb/GWh	0.00090 lb/GWh	0.00090 lb/GWh	0.0060	0.020 lb/GWh.
Mercury, Hg	NA	NA	NA	0.00010 lb/GWh	NA.
Manganese, Mn	0.0040 lb/GWh	0.0040 lb/GWh	0.0040 lb/GWh	0.030	0.0070 lb/GWh.
Nickel, Ni	0.0040 lb/GWh	0.0040 lb/GWh	0.0040 lb/GWh	0.040	0.0070 lb/GWh.
Selenium, Se	0.030 lb/GWh	0.030 lb/GWh	0.030 lb/GWh	0.0040	0.00090 lb/GWh.

* Beyond-the-floor as discussed elsewhere.

NA = Not applicable.

Most, if not all, coal-fired EGUs and solid oil-derived fuel-fired EGUs already have emission limitations for SO[2] under either the Federal NSPS, individual SIP programs, or the Federal ARP and, as a result, have

SO[2] emission controls installed. Further, again most, if not all, coal-fired EGUs have SO[2] CEMS installed and operating under the provisions of one of these programs. Thus, as SO[2] is a suitable surrogate for the acid gas HAP, it could be used as an alternate equivalent standard to the HCl standard for EGUs with FGD systems installed and operated at normal capacity. An SO[2] standard would ensure that equivalent control of the acid gas HAP is achieved, and some facilities may find it preferable to use the existing SO[2] CEMS for compliance purposes rather than having to perform the manual HCl compliance testing. As noted elsewhere, this approach does not work for EGUs that do not have SO[2] controls installed and, thus, those EGUs may not utilize the alternate SO[2] limitations. Further, no SO[2] data were provided by the two IGCC units; therefore, there is no alternative SO[2] limitation being proposed for existing IGCC units.

Some sources have expressed a preference for individual non-Hg metal HAP emission limitations rather than the use of PM as a surrogate. Thus, EPA has analyzed the data for that purpose and we are proposing both alternate individual HAP metal limitations and total HAP metal limitations for all subcategories except liquid oil-fired EGUs. These limitations provide equivalent control of metal HAP as the proposed PM limitations.

We are soliciting comments on all aspects of these alternate emission limitations.

VI. Background Information on the Proposed NSPS

A. What is the statutory authority for this proposed NSPS?

New source performance standards implement CAA section 111(b), and are issued for source categories which EPA has determined cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. CAA section 111(b)(1)(B) requires the EPA to periodically review and, if appropriate, revise the NSPS to reflect improvements in emissions reduction methods.

CAA section 111 requires that the NSPS reflect the application of the best system of emissions reductions which the Administrator determines has been adequately demonstrated (taking into account the cost of achieving such reduction, any non-air quality health and environmental impacts and energy requirements). This level of control is commonly referred to as best demonstrated technology (BDT).

The current standards for steam generating units are contained in the NSPS for electric utility steam generating units (40 CFR part 60, subpart Da), industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db), and small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc). Previous standards that continue to apply to owners/operators of existing affected facilities, but which have been superseded for owner/operators of new affected facilities, are contained in the NSPS for fossil-fuel-fired steam generating units for which construction was commenced after August 17, 1971, but on or

before September 18, 1978 (40 CFR part 60, subpart D).

B. Summary of State of New York, et al., v. EPA Remand

On February 27, 2006, EPA promulgated amendments to the NSPS for EGUs (40 CFR part 60, subpart Da) which established new standards for PM, SO[2], and NO[X] *(71 FR 9,866)*. EPA was subsequently sued on the amendments by multiple state governments, municipal governments, and environmental organizations (collectively the Petitioners). *State of New York v. EPA*, No. 06-1148 (DC Cir.). The Petitioners alleged that EPA failed to correctly identify the best system of emission reductions for the newly established SO[2] and NO[X] standards. The Petitioners also contended that EPA was required to establish separate emission limits for fine filterable PM (PM[2.5]) and condensable PM. Finally, the petitioners claimed the NSPS failed to reflect the degree of emission limitation achievable through the application of IGCC technology. Based upon further examination of the record, EPA determined that certain issues in the rule warranted further consideration. On that basis, EPA sought and, on September 4, 2009, was granted a voluntary remand without vacatur of the 2006 amendments.

C. EPA's Response to the Remand

The emission standards established by the 2006 final rule, which are more stringent than the standards in effect prior to the adoption of the amendments, remain in effect and will continue to apply to affected facilities for which construction was commenced after February 28, 2005, but before May 4, 2011. Following careful consideration of all of the relevant factors, EPA is proposing to establish amended standards for PM,

SO[2], and NO[X] which would apply to owners/operators of affected facilities constructed, reconstructed, or modified after May 3, 2011.

In terms of the timing of our response to the remand, we consider it appropriate to propose revisions to the NSPS in conjunction with proposing the EGU NESHAP. There are some commonalities among the controls needed to comply with the requirements of the two rules and syncing the two rules so that they apply to the same set of new sources will allow owners/operators of those sources to better plan to comply with both sets of requirements. Therefore, we are proposing these revisions in conjunction with proposing the NESHAP, and intend to finalize both rules simultaneously.

As explained in more detail below and in the technical support documents, we have concluded that the proposed PM, SO[2], and NO[X] standards set forth in this proposed rule reflect BDT. In addition, we have concluded that the most appropriate approach to reduce emissions of both filterable PM[2.5] and condensable PM is to establish a total PM standard, rather than establishing separate standards for each form of PM.The total PM standard, total filterable PM plus condensable PM, set forth in this proposed rule reflects BDT for all forms of PM. We have concluded that establishing a single total PM standard is preferable for a number of reasons. First, this approach effectively accounts for and requires control of both primary forms of PM, filterable PM, which includes both filterable PM[10] (PM in the stack with an aerodynamic diameter less than or equal to a nominal 10 micrometers) and filterable PM[2.5] (PM in the stack with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers) and condensable PM

(materials that are vapors or gases at stack conditions but form solids or liquids upon release to the atmosphere). Second, we have concluded that the same control device constitutes BDT for both forms of filterable PM. Best demonstrated technology for control of both filterable PM[10] and filterable PM[2.5] emissions from steam generating units is based upon the use of a FF with coated or membrane filter media bags. Fabric filters control the fine particulate sizes that compose filterable PM[2.5] and the coarser particulate sizes that are a component of filterable PM[10] through the same means. Since a FF controls total filterable PM and cannot selectively control filterable PM[2.5], establishing separate filterable PM[2.5] and filterable PM[10] standards would not result in any further reduction in emissions. Thus, although the NSPS for steam generating units do not establish individual standards for filterable PM[10] and PM[2.5], the NSPS PM standards for steam generating units do result in control of both of these filterable PM size categories based on the use of the control technologies identified as BDT and used to derive the proposed PM standards. Third, size fractionation of the PM in stacks with entrained water droplets (i.e., those downstream of a wet FGD scrubber) is challenging since the water droplets contain suspended and dissolved material which would form particulate after exiting the stack when the water droplet is evaporated. This challenge is exacerbated due to the difficulties of collecting the water droplets and quickly evaporating the water to reconstitute the suspended and dissolved materials in their eventual final size without changing their size as a result of shattering, agglomeration and deposition on the sample equipment. Although the Agency and others are working toward technologies that may allow particle sizing in

wet stack conditions, there is currently no viable test method to determine the size fraction of the filterable PM for stacks that contain water droplets. Because many new EGUs are expected to use wet scrubbers and/or a WESP, owners/operators of these units would have no method to determine compliance with a fine filterable PM standard.

Under the existing NSPS, BDT for an owner/operator of a new affected facility is a FF for control of filterable PM and an FGD for control of SO[2]. Depending on the specific stack conditions and coal type being burned, fabric filters may also provide some co-benefit reduction in condensable PM emissions. Furthermore, an FGD designed for SO[2] control has the co-benefit of reducing, to some extent, condensable PM emissions. Therefore, the existing NSPS baseline for control of condensable PM is a FF in combination with an FGD. We have concluded that the additional use of a WESP system in combination with DSI is BDT for condensable PM. We have concluded that it is appropriate to regulate both filterable and condensable PM under a single standard since they may be impacted differently by common controls. For example, DSI is one of the approaches that could be used to reduce the sulfuric acid mist (SO[3] and H[2] SO[4]) portion of the condensable PM. However, addition of sorbent adds filterable PM to the system and could conceivably increase filterable PM emissions. When using a wet FGD, some small amount of scrubber solids (gypsum, limestone) can be entrained into the exiting gas, resulting in an increase in filterable PM emissions. In each of these cases, technologies used to meet a stringent separate condensable PM standard could result in an increase in filterable PM emissions, a portion of which consist of fine filterable PM. This increase in filterable PM may challenge the ability of

the owner/operator of the affected facility to meet a similarly stringent filterable PM standard. Filterable and condensable PM are often controlled using separate or complimentary technologies—though there are technologies, (*e.g.*, WESP), that can control both filterable and condensable PM emissions. Often times the equipment is used to also control other pollutants such as SO[2], HCl, and Hg. A combined PM standard allows for optimal design and operation of the control equipment. Thus, with the data available to us it is unclear what system of emissions reduction would result in the best overall environmental performance if we attempted to established separate filterable and condensable PM standards and what an appropriate condensable PM standard would be. At this time, the use of a total PM standard is the most effective indicator that the emissions standard is providing the best control of both filterable and condensable PM[2.5] emissions as well as coarse filterable PM emissions. We are requesting comment on whether separate filterable PM[2.5] and condensable PM standards would be appropriate and what the numerical values of any such standards should be.

EPA disagrees with the petitioners claim that the NSPS should be based on the performance of IGCC units. The NSPS is a national standard and IGCC is not appropriate in every situation. Although IGCC units have many advantages, technology choice is based on several factors, including the goals and objectives of the owner or operator constructing a facility, the intended purpose or function of the facility, and the characteristic of the particular site. In addition, the emissions benefits resulting from reduced emissions of criteria pollutants are not sufficient in all instances to justify the higher capital costs of today's IGCC units if IGCC is selected as BDT

in establishing a national standard. The emissions benefits may, however, be sufficient to justify the use of IGCC in an individual case, after considering cost and other relevant factors, including those described above.

D. EPA's Response to the Utility Air Regulatory Group's Petition for Reconsideration

On January 28, 2009, EPA promulgated amendments separate from the above mentioned amendments to the NSPS for EGUs (40 CFR part 60, subpart Da, *74 FR 5,072).* The Utility Air Regulatory Group (UARG) subsequently requested reconsideration of that rulemaking and EPA granted that reconsideration. Specific issues raised by UARG included the opacity monitoring requirements for owners/operators of affected facilities subject to an opacity standard that are not required to install a continuous opacity monitoring system (COMS). Another issue raised by UARG was the opacity standard for owners/operators of affected facilities subject to 40 CFR part 60, subpart D. We are requesting comments on both of these issues in this rulemaking.

VII. Summary of the Significant Proposed NSPS Amendments

The proposed amendments would amend the emission limits for PM, SO[2], and NO[X] from steam generating units in 40 CFR part 60, subpart Da. Only those facilities that begin construction, modification, or reconstruction after May 3, 2011 would be affected by the proposed amendments. In addition to proposing to amend the identified emission limits, we are also proposing several less significant amendments, tech-

nical clarifications, and corrections to various provisions of the existing utility and industrial steam generating unit NSPS, as explained below.

A. What are the proposed amended emissions standards for EGUs?

We are proposing to amend the PM, SO[2], and NO[X] standards for owners/operators of new, modified, and reconstructed units on which construction is commenced after May 3, 2011 as follows. We are proposing a total PM emissions standard (filterable plus condensable PM) for owners/operators of new and reconstructed EGUs of 7.0 nanograms per joule (ng/J) (0.055 lb/MWh) gross energy output. The proposed PM standard for modified units is 15 ng/J (0.034 lb/MMBtu) heat input.

We are proposing an SO[2] emissions standard for new and reconstructed EGUs of 130 ng/J (1.0 lb/MWh) gross energy output or a 97 percent reduction of potential emissions regardless of the type of fuel burned with the following exception. We are not proposing to amend the SO[2] emissions standard for EGUs that burn over 75 percent coal refuse. We are also not proposing to amend the SO[2] emission standard for owners/operators of modified EGUs because of the incremental cost effectiveness and potential site specific limited water availability. Without access to adequate water supplies owners/operators of existing facilities would not be able to operate a wet FGD.

We are co-proposing two options for an amended NO[X] emissions standard. EPA's preferred approach would establish a combined NO[X] plus CO standard for owners/operators of new, reconstructed, and modified units. The proposed combined standard for new and reconstructed EGUs is 150 ng/J (1.2 (lb

NO[X] + lb CO)/MWh) and the proposed combined standard for modified units is 230 ng/J (1.8 (lb NO[X] + lb CO)/MWh). EPA prefers the approach of establishing a combined standard because it provides additional compliance flexibility while still providing an equivalent or superior level of environmental protection. Alternatively, we are proposing to amend the NO[X] emission standard for new, modified, and reconstructed EGUs to 88 ng/J (0.70 lb/MWh) gross energy output regardless of the type of fuel burned and not establish any CO standards.

In addition to proposing revised emission standards, we are also proposing to amend the way an owner/operator of an affected facility would calculate compliance with the proposed standards. Under the existing NSPS, averages are calculated as the arithmetic average of the non out-of-control hourly emissions rates (*i.e.*, hours during which the monitoring device has not failed a quality assurance or quality control test) during the applicable averaging period. For the revised standards, we are proposing that the average be calculated as the sum of the applicable emissions divided by the sum of the gross output of non out-of-control hours during the averaging period. We are proposing this change in part to facilitate moving from the existing PM, SO[2], and NO[X] standards, which exclude periods of startup and shutdown, to the proposed PM, SO[2,] and NO[X] standards, which would include periods of startup and shutdown.

B. Would owners/operators of any EGUs be exempt from the proposed amendments?

We are proposing several amendments that would exempt owners/operators from certain of the proposed amendments. First, we are proposing that owners/

operators of innovative emerging technologies that apply for and are granted a commercial demonstration permit by the Administrator for an affected facility that uses a pressurized fluidized bed, a multi-pollutant emissions control system, or advanced combustion controls be exempt from the proposed amended standard. Owners/operators of these technologies would instead demonstrate compliance with standards similar to those finalized in the 2006 amendments. The total PM standard would be 0.034 lb/MMBtu heat input, the SO[2] standard would be 1.4 lb/MWh gross output or a 95 percent reduction in potential emissions, and the NO[X] standard would be 1.0 lb/MWh gross output. In the event we finalize a combined NO[X] /CO standard, the corresponding combined limit would be 1.4 lb/MWh gross output. In addition, we are proposing to harmonize all of the steam generating unit NSPS by exempting all steam generating units combusting natural gas and/or low sulfur oil from PM standards and exempting all steam generating units burning natural gas from opacity standards. Finally, we are proposing to exempt owners/operators of affected facilities subject to 40 CFR part 60, subpart Eb (standards of performance for large MWCs), from 40 CFR part 60, subpart Da, exempt owners/operators of affected facilities subject to 40 CFR part 60, subpart CCCC (standards of performance for commercial and industrial solid waste incineration), units from 40 CFR part 60, subparts Da, Db, and Dc, exempt owners/operators of affected facilities subject to 40 CFR part 60, subpart BB (standards of performance for Kraft pulp mills), from the PM standards under 40 CFR part 60, subpart Db, and exempt owners/operators of fuel gas combustion devices subject to 40 CFR part 60, subpart Ja (standards of performance for petroleum refineries),

from the SO[2] standard under 40 CFR part 60, subpart Db.

C. What other significant amendments are being proposed?

A complete list of the corrections and technical amendments and corrections is available in the docket in the form of a redline/strikeout version of the existing regulatory language. These additional amendments are being proposed to clarify the intent of the current requirements, correct inaccuracies, and correct oversights in previous versions that were promulgated. The additional significant amendments are as follows.

We are proposing several definitional changes. First, to provide additional flexibility and recognize the environmental benefit of efficient production of electricity we are proposing to expand the definition of the affected facility under 40 CFR part 60, subpart Da, to include integrated CTs and fuel cells. Second, because petroleum coke is increasingly being burned in EGUs selling over 25 MW of electric output, we are proposing to amend the definition of petroleum to include petroleum coke. Next, to minimize permitting and compliance burdens and avoid situations where an IGCC facility switches between different NSPS (40 CFR part 60, subparts KKKK and Da), we are proposing to amend the definition of an IGCC facility to allow the Administrator to exempt owners/operators from the 50 percent solid-derived fuel requirement during construction and repair of the gasifier. Owners/operators of IGCC units might install and operate the stationary CT prior to completion of the gasification system. Under the existing standards, an owner/operator doing this would first be subject to 40 CFR part 60, subpart KKKK, and applicability

would switch once the gasification system is completed. This outcome would not result in any additional reduction in emissions. The proposed change would thus reduce regulatory burden without decreasing environmental protection. Finally, both biodiesel and kerosene have combustion characteristics similar to those of distillate oil. Therefore, we are proposing to expand the definition of distillate oil in 40 CFR part 60, subparts Db and Dc, to include both biodiesel and kerosene such that units burning any of these fuels, either separately or in combination would be subject to the same requirements.

Additional proposed amendments include deleting vacated provisions and additional harmonization across the various steam generating unit NSPS. As explained above, CAMR was vacated by the DC Circuit Court in 2008. As a result, the provisions added to 40 CFR part 60, subpart Da, by CAMR are no longer enforceable. Therefore, we are proposing to delete the provisions in 40 CFR part 60, subpart Da, that reference Hg standards and Hg testing and monitoring provisions. In addition, existing 40 CFR part 60, subpart HHHH (Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units), which was promulgated as part of CAMR, and was, therefore, also vacated by the court's decision, will be removed and that subpart will be deleted. We are proposing to harmonize all of the steam generating unit NSPS by adding BLDS and ESP parameter monitoring systems as alternatives to the requirement to install a COMS in all the subparts (40 CFR part 60, subparts D, Da, Db, and Dc). We are also proposing to change the date by which owners/operators of affected facilities subject to all of the steam generating unit NSPS are to begin submitting performance test data electronically from July 1, 2011, to January 1, 2012.

VIII. Rationale for This Proposed NSPS

The proposed new emission standards for EGUs would apply only to affected sources that begin construction, modification, or reconstruction after May 3, 2011. Based on our review of emission data and control technology information applicable to criteria pollutants, we have concluded that amendments of the PM, SO[2], and NO[X] emission standards are appropriate. The technical support documents that accompany the proposal describe in further detail how the proposed amendments to the NSPS reflect the application of the BDT for these sources considering the performance and cost of the emission control technologies and other environmental, health, and energy factors. In establishing the proposed revised emission limits based on BDT, we have to the extent that it is practical and reasonable to do so adopted a fuel and technology neutral approach and have expressed the proposed emission limits on an output basis. These approaches provide the level of emission limitation required by the CAA for the NSPS program while at the same time achieving the additional benefits of compliance flexibility, increased efficiency, and the use of cleaner fuels.

The fuel and technology neutral approach provides a single emission limit for steam generating units based on the application of BDT without regard to the specific type of steam generating equipment or fuel being used. We have concluded that this approach provides owners/operators of affected facilities an incentive to carefully consider fuel use, boiler type, and control technology in planning for new units so as to use the most effective combination of add-on control technologies, clean fuels, and boiler design based on the circumstances to meet the emission standards.

To develop a fuel- and technology-neutral emission limit, we first analyzed data on emission control performance from coal-fired units to establish an emission level that represents BDT for units burning coal. We adopted this approach because the higher sulfur, nitrogen, and ash contents for coal compared to oil or gas makes application of BDT to coal-fired units more complex than application of BDT to either oil- or gas-fired units. Because of these complexities, emission levels selected for coal-fired steam generating units using BDT would also be achievable by oil- and gas-fired EGUs. Thus, we are proposing that the emission levels established through the application of BDT to coal-fired units apply to all boiler types and fuel use combinations. We have concluded that this fuel-neutral approach both satisfies the requirements of CAA section 111(b) and provides a clear incentive to use cleaner fuels where it is possible to do so.

Where feasible, we are proposing output-based (gross basis) standards in furtherance of pollution prevention which has long been one of our highest priorities. In the current context, maximizing the efficiency of energy generation represents a key opportunity to further pollution prevention. An output-based format establishes emission standards that encourage unit efficiency by relating emissions to the amount of useful-energy generated, not the amount of fuel burned. By relating emission limitations to the productive output of the process, output-based emission standards encourage energy efficiency because any increase in overall energy efficiency results in a lower emissions rate. Output-based standards provide owners/operators of regulated sources with an additional compliance option (*i.e.*, increased efficiency in producing useful output) that can result in both reduced compliance costs and lower emissions.

The use of more efficient generating technologies reduces fossil fuel use and leads to multi-media reductions in environmental impacts both on-site and off-site. On-site benefits include lower emissions of all products of combustion, including HAP, as well as reducing any solid waste and wastewater discharges. Off-site benefits include the reduction of emissions and non-air environmental impacts arising from the production, processing, and transportation of fuels and the disposal of by-products of combustion such as fly-ash and bottom-ash.

The general provisions in 40 CFR part 60 provide that "emissions in excess of the level of the applicable emissions limit during periods of startup, shutdown, and malfunction (shall not be) considered a violation of the applicable emission limit unless otherwise specified in the applicable standard." *40 CFR 60.8(c)*. EPA is proposing standards in this rule that apply at all times, including during periods of startup or shutdown, and periods of malfunction. In proposing the standards in this rule, EPA has taken into account startup and shutdown periods and, for the reasons explained below, has not proposed different standards for those periods.

To establish the proposed output-based SO[2] and NO[X] standards, we used hourly pollutant emissions data and gross output data as reported to the Clean Air Markets Division (CAMD) of EPA. In general, retrofit existing units can perform as well as recently operational units. To establish a robust data set on which to base the proposed amendments, we analyzed emissions data from both older plants that have been retrofitted with controls and recently operational units. We did not attempt to filter out periods of

startup or shutdown and the proposed standards, therefore, account for those periods.

If any persons believe that our conclusion is incorrect, or that we have failed to consider any relevant information on this point, we encourage them to submit comments. In particular, we note that the general provisions in 40 CFR part 60 require facilities to keep records of the occurrence and duration of any startup, shutdown or malfunction (*40 CFR 60.7(b)*) and either report to EPA any period of excess emissions that occurs during periods of startup, shutdown, or malfunction (*40 CFR 60.7(c)(2)*) or report that no excess emissions occurred (*40 CFR 60.7(c)(4)*). Thus, any comments that contend that sources cannot meet the proposed standard during startup and shutdown periods should provide data and other specifics supporting their claim.

In developing the proposed 30-day SO[2] and NO[X] standards, we summed the unadjusted emissions for all non-out-of-control operating hours and divided that value by the sum of the gross electrical energy output over the same period. For the purposes of this analysis, out-of-control hours were defined as when either the unadjusted applicable emissions or gross output could not be determined for that operating hour. The reduction in potential SO[2] emissions was calculated by comparing the reported SO[2] emissions during a 30-day period to the potential emissions for that same 30-day period. Potential uncontrolled SO[2] emissions were calculated using monthly delivered fuel receipts and fuel quality data from the EIA forms EIA-923, EIA-423, and FERC-423, as applicable. For each operating day, the total potential uncontrolled SO[2] emissions were calculated by multiplying the uncontrolled SO[2] emissions rate for the applicable

month as determined using the EIA data by the heat input for that day. This revised averaging approach gives more weight to high load hours and more accurately reflects overall environmental performance. In addition, because low load hours do not factor as heavily into the calculated average the impact of including periods of startup and shutdown is minimized.

Particulate matter and CO data are not reported to CAMD and instead were collected as part of the 2010 ICR. Total PM testing was reported as part of the 2010 ICR and those data were used in both rulemakings. As part of the 2010 ICR, owners/operators reported CO performance test data and whether or not they have a CO CEMS installed on their facility. We requested CO CEMS data from multiple units to compare the relationship between NO[X] and CO. The 30-day combined NO[X] /CO standard was calculated using the same approach as for NO[X] and SO[2].

A. How are periods of malfunction addressed?

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *" (*40 CFR 60.2.*) EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 111 standards. Further, nothing in CAA section 111 or in case law requires that EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards. *See,*

Weyerhaeuser v Costle, 590 F.2d 1011, 1058 (DC Cir. 1978) ("In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.")

Further, it is reasonable to interpret CAA section 111 as not requiring EPA to account for malfunctions in setting emissions standards. For example, we note that section 111 provides that EPA set standards of performance which reflect the degree of emission limitation achievable through "the application of the best system of emission reduction" that EPA determines is adequately demonstrated. Applying the concept of "the application of the best system of emission reduction" to periods during which a source is malfunctioning presents difficulties. The "application of the best system of emission reduction" is more appropriately understood to include operating units in such a way as to avoid malfunctions.

Moreover, even if malfunctions were considered a distinct operating mode, we believe it would be impracticable to take malfunctions into account in setting CAA section 111 standards for EGUs under 40 CFR part 60, subpart Da. As noted above, by definition, malfunctions are sudden and unexpected events and it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources in the

category. Moreover, malfunctions can vary in frequency, degree, and duration, further complicating standard setting.

In the event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. EPA would also consider whether the source's failure to comply with the CAA section 111 standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or careless operation." *40 CFR 60.2* (definition of malfunction).

Finally, EPA recognizes that even equipment that is properly designed and maintained can sometimes fail. Such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g.*, State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (September 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (February 15, 1983)). EPA is, therefore, proposing to add an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. *See 40 CFR 60.41Da* (defining "affirmative defense" to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also are

proposing other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in *40 CFR 60.46Da*. (*See 40 CFR 22.24*). These criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in *40 CFR 60.2* (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions "[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *" The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with *40 CFR 60.40Da* and to prevent future malfunctions. For example, the source would have to prove by a preponderance of the evidence that "[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *" and that "[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *" In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met the burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with CAA section 113 (see also 40 CFR part 22.77).

B. How did EPA determine the proposed emission limitations?

1. Selection of the Proposed PM Standard

Controls for filterable PM are well established. Either an ESP or FF can control both coarse and fine filterable PM. However, controls for condensable PM are less developed. Condensable PM from a coal-fired boiler is composed primarily of SO[3] and H[2] SO[4] but may also contain smaller amounts of nitrates, halides, ammonium salts, and volatile metals such as compounds of Hg and Se. Controls that are expected to reduce emissions of condensable PM include the use of lower sulfur coals, the use of an SCR catalyst or other NO[X] control device with minimal SO[2] to SO[3] conversion, use of an FGD scrubber, injection of an alkaline sorbent upstream of a PM control device, and use of a WESP Other control technologies such as FFs or ESPs may also provide some reduction in condensable PM—depending on the flue gas temperature and the composition of the fly ash and other bulk PM. It is unlikely that owners/operators of modified units could universally further reduce the condensable fraction of the PM as they already have FGD controls, operating the PM control at a cooler temperature (or relocating to a cooler location) are not practical options due to concerns with corrosion, and it is possible that the existing ductwork might not make DSI viable without significant adjustments. Therefore, we have concluded that BDT for modified units should be based on the use of a FF in combination with an FGD. Based on the 2010 ICR data for total PM, there are performance tests for 63 units below the existing NSPS filterable PM standard (0.015 lb/MMBtu), that have some type of SO[2] control, and that use a FF. Ninety four percent of these performance tests are achieving an

emissions rate of 0.034 lb/MMBtu for total PM, and we have concluded that this value is an achievable standard for owners/operators of modified units. It is also approximately equivalent in stringency to the existing filterable PM standard because no specific condensable PM controls would necessarily be required. However, we have concluded that new EGUs will factor in condensable PM controls. BDT for new EGUs would be a FF and FGD in combination with both DSI and a WESP. Based on the 2010 ICR data for total PM, there are performance tests for 48 units below the existing NSPS filterable PM standard (0.015 lb/MMBtu), that have some type of SO[2] control, that use a FF, and that reported gross electrical output during the performance test. Because no owners/operators of EGUs are presently specifically attempting to control condensable PM beyond eliminating the visible blue plume that can occur from sulfuric acid mist emissions, we concluded it was appropriate to use the top 20 percentile of the performance test data for the proposed total PM standard. The top 20 percentile of these performance tests is 7.0 ng/J (0.055 lb/MWh). We are soliciting comments on the proposed standard and are considering the range of 15 ng/J (0.034 lb/MMBtu) to 5.0 ng/J (0.040 lb/MWh) for the final rule. We are also requesting comment on whether an input-based standard is more appropriate for standards where compliance is based on performance tests instead of CEMS.

2. How did EPA select the proposed SO[2] standard?

A number of SO[2] control technologies are currently available for use with new coal-fired EGUs. Owners/operators of new steam generating projects that use IGCC technology can remove the sulfur associated with the coal in downstream processes after

the coal has been gasified. Owner/operators of new steam generating units that use FBC technology can control SO[2] during the combustion process by adding limestone into the fluidized-bed, and, if necessary, installing additional post-combustion controls. Owners/operators of steam generating units using PC combustion technology can use post-combustion controls to remove SO[2] from the flue gases. Additional control strategies that apply to all steam generating units include the use of low sulfur coals, coal preparation to improve the coal quality and lower the sulfur content, and fuel blending with inherently low sulfur fuels.

To assess the SO[2] control performance level of EGUs, we reviewed new and retrofitted units with SO[2] controls. Table 17 of this preamble shows the performance of several of the best performing units in terms of percent reduction in potential SO[2] emissions identified in our analysis of coal-fired EGUs.

Table 17—SO[2] Emissions Performance Data

Facility	Time period	Maximum	Minimum
		30-day SO[2] emissions rate (lb/MWh)	30-day percent SO[2] reduction
Cayuga 1	12/08-12/09	1.03	97.4
Harrison 1	01/06-01/09	1.45	96.7
Harrison 2	01/06-01/09	1.01	97.7
Harrison 3	01/06-01/09	0.97	98.2
HL Spurlock 1	06/09-12/09	1.83	96.9
HL Spurlock 2	11/08-12/09	1.26	98.0
HL Spurlock 3	01/09-12/09	1.45	96.5
HL Spurlock 4	01/09-12/09	1.08	97.7
Wansley 1	02/09-12/09	0.31	97.7
Wansley 2	05/09-12/09	0.37	97.4
Iatan 1	04/09-12/09	0.16	98.2
Jeffrey 2	05/09-12/09	0.09	99.0

Table 17—SO[2] Emissions Performance Data

Facility	Time period	Maximum	Minimum
		30-day SO[2] emissions rate (lb/MWh)	30-day percent SO[2] reduction
Jeffrey 3	04/09-12/09	0.13	98.5
Trimble County 1	01/05-12/09	1.14	97.6
Mountaineer 1	05/07-12/09	1.15	97.6

With the exception of the HL Spurlock 3 and 4 units all of the listed units use wet limestone-based scrubbers. HL Spurlock 3 and 4 are FBC boilers that remove the majority of SO[2] using limestone injection into the boiler and then remove additional SO[2] by lime injection into the ductwork prior to the FF. Of the identified best performing units, we only have multiple years of performance data for the Harrison, Trimble County, and Mountaineer units. Based on the performance of these units, we have concluded that 97 percent reduction in potential SO[2] emissions has been demonstrated and is achievable on a long term basis. This level of reduction has also been demonstrated at each separate unit at each location in Table 17 of this preamble and accounts for variability in performance of individual scrubbers. Therefore, the proposed upper limit on a percent reduction basis is 97 percent. Even though the Iatan and Jeffrey units are achieving a 98 percent reduction in potential SO[2] emissions, we are not proposing this standard because it is based on relatively short-term data. Based on the variability in SO[2] reductions from the Harrison, Trimble County, and Mountaineer units, we have concluded that short-term data do not necessarily take into account the range of operating conditions that a

facility would be expected to operate or control equipment variability and degradation. We are soliciting comments on the proposed limit and are considering the range of 96 to 98 percent reduction in potential SO[2] emissions for the final rule.

To determine an appropriate alternate numerical standard, we evaluated the performance of several recently constructed units in addition to the numerical standards for the units in Table 17 of this preamble. Table 18 of this preamble shows the maximum 30-day average SO[2] emissions rate of units that commenced operation between 2005 and 2008, that are emitting at levels below the current NSPS, and that reported both SO[2] emissions and gross electric output data to CAMD.

Table 18—SO[2] Emissions Performance Data for New EGUs

Facility	SO[2] control technology	In service date	Maximum 30-day SO[2] emissions rate (lb/MWh)
Weston 4	Lime-based Spray Dryer	2008	0.61
Cross 4	Wet Limestone FGD	2008	1.02
TS Power Plant 1	Lime-based Spray Dryer	2008	0.56
Wygen II	Lime-based Spray Dryer	2008	0.95
Walter Scott Jr.	Lime-based Spray	2007	0.73

Table 18—SO[2] Emissions Performance Data for New EGUs

Facility	SO[2] control technology	In service date	Maximum 30-day SO[2] emissions rate (lb/MWh)
Energy Center 4 Dryer			
Cross 3	Wet Limestone FGD	2007	1.06
Springerville TS3	Lime-based Spray Dryer	2006	1.04
HL Spurlock 3	Fluidized Bed Limestone Injection + Lime Injection	2005	1.45

The HL Spurlock 3 unit is the only new unit that burns high sulfur coal and that unit could meet the proposed alternate percent reduction standard. However, it would not be expected to achieve a numerical standard based on the performance of the other units. Further, with the exception of the Cross 3 and 4 units, which burn medium sulfur bituminous coals, the remaining units burn lower-sulfur subbituminous coals. To provide the maximum emissions reduction, we further concluded that the alternate numerical standard should be as stringent as the numerical rates achieved by the units used to determine the percent reduction standard. If the alternate numerical standard were less stringent than the emissions rate achieved by the units used to determine the maximum percent reduction, those units would not be required to achieve the maximum percent reduction that has

been demonstrated. In addition, the numerical standard should account for variability in today's SO[2] control technologies and provide sufficient compliance margin for owners/operators of new units burning medium sulfur coals to comply with the numerical standard and thereby provide an incentive to burn cleaner fuels. The sulfur concentrations in the flue gas of EGUs burning medium and low sulfur coals is more diffuse than for EGUs burning high sulfur coals, and it has not been demonstrated that units burning these coals would be able to achieve 97 percent reduction of potential emissions on a continuous basis. We are proposing 1.0 lb/MWh as the alternate numerical standard because it provides a comparable level of performance to the 97 percent reduction requirement and satisfies criteria mentioned above. The numerical standard would require at least 80 percent reduction even from the lowest sulfur coals and would accommodate the use of traditional spray dryer scrubbers for owner/operators of new units burning coal with uncontrolled SO[2] emissions of up to approximately 1.6 lb/MMBtu.

Based on the performance of the spray dryer at the Springerville TS3 unit, the numerical standard would provide sufficient flexibility such that an owner/operator of an EGU could burn over 90 percent of the subbituminous coals presently being used in combination with a spray dryer. This technology choice provides owners/operators the flexibility to minimize water use and associated waste water discharge, as well as reducing additional CO[2] that is chemically created as part of the SO[2] control device. Even though there is not necessarily an overall greenhouse (GHG) reduction from using a lime-based instead of a limestone-based scrubber, lime production facilities have relatively concentrated CO[2] streams.

Capture and storage of CO[2] at the lime manufacturing facility could potentially be easier since separation of the CO[2] would not be necessary, as is the case with an EGU exhaust gas. Owners/operators of new and reconstructed units burning coals with higher uncontrolled SO[2] emissions would either have to use IGCC with a downstream process to control sulfur prior to combustion, FBC, or a wet SO[2] scrubbing system to comply with the proposed standard. The proposed limit would allow the higher sulfur coals (uncontrolled emissions of greater than approximately 3 lb SO[2] /MMBtu) to demonstrate compliance with the 97 percent reduction requirement as an alternate to the numerical limit. We are soliciting comments on the proposed limit and are considering the range of 100 to 150 ng/J (0.80 to 1.2 lb/MWh) for the final rule.

Coal refuse (also called waste coal) is a combustible material containing a significant amount of coal that is reclaimed from refuse piles remaining at the sites of past or abandoned coal mining operations. Coal refuse piles are an environmental concern because of acid seepage and leachate production, spontaneous combustion, and low soil fertility. Units that burn coal refuse provide multimedia environmental benefits by combining the production of energy with the removal of coal refuse piles and by reclaiming land for productive use. Consequently, because of the unique environmental benefits that coal refuse-fired EGUs provide, these units warrant special consideration so as to prevent the amended NSPS from discouraging the construction of future coal refuse-fired EGUs in the U.S.

Coal refuse from some piles has sulfur contents at such high levels that they present potential economic and technical difficulties in achieving the same SO[2]

standard that we are proposing for higher quality coals. Therefore, so as not to preclude the development of these projects, we are proposing to maintain the existing SO[2] emissions standard for owners/operators of affected facilities combusting 75 percent or more coal refuse on an annual basis.

We are proposing to maintain the existing SO[2] standard for modified units to preserve the use of spray dryer FGD. Existing units might not have access to adequate water for wet FGD scrubbers and it is not generally cost effective to upgrade existing spray dryer FGD scrubbers to a wet FGD scrubber. In addition, the 90 percent sulfur reduction for modified units also allows existing modified FBCs to comply without the addition of post-combustion SO[2] controls. We have concluded that it is not generally cost effective to add additional post combustion SO[2] controls for modified fluidized beds.

3. Selection of the Proposed NO[X] Standard

In the 2006 final NSPS amendments *(71 FR 9866),* EPA concluded that advanced combustion controls were BDT. However, upon further review we have concluded this was not appropriate. Although select existing PC EGUs burning subbituminous coals have been able to achieve annual NO[X] emissions of less than 1.0 lb/MWh (*e.g.,* Rush Island, Newton), PC EGUs burning other coal types using only combustion controls have not demonstrated similar emission rates. Lignite-fired PC EGUs have only demonstrated an annual NO[X] emissions rate of 1.7 lb/MWh (*e.g.,* Martin Lake) and the best bituminous fired PC EGUs using only combustion controls are slightly higher than 2.0 lb/MWh on an annual basis (*e.g.,* Jack McDonough, Brayton Point, AES Cayuga, Genoa). The variability in NO[X] control technologies results in a

maximum 30-day average emissions rate typically being 1/4 to 1/3 higher than the annual average emissions rate. Therefore, it has not been demonstrated that owners/operators of PC EGUs burning any coal type using advanced combustion controls could comply with the existing NO[X] standard.

After re-evaluating the performance, costs, and other environmental impacts of adding SCR in addition to combustion controls, we have concluded that combustion controls in combination with SCR represents BDT for continuous reduction of NO[X] emissions from EGUs. Therefore, the regulatory baseline for NO[X] emissions is defined to be combustion controls in combination with the installation of SCR controls on all new PC-fired units.

To assess the NO[X] control performance level of EGUs, we reviewed new and retrofitted units with post combustion NO[X] controls. Table 19 of this preamble shows the performance of several of the best performing units identified in our analysis of coal-fired EGUs.

Table 19—NO[X] Performance Data

Facility	Time period	Maximum 30-day NO[X] emissions rate (lb/MWh)	Boiler type & primary coal rank
Havana 9	01/05-12/09	0.70	PC, Sub.
Walter Scott Jr. 4	04/07-12/09	0.58	PC, Sub.
Mirant Morgantown 1	06/07-12/09	0.65	PC, Bit.
Mirant Morgantown	06/08-12/09	0.70	PC, Bit.

Table 19—NO[X] Performance Data

Facility	Time period	Maximum 30-day NO[X] emissions rate (lb/MWh)	Boiler type & primary coal rank
2			
Roxboro 2	01/09-12/09	0.67	PC, Bit.
Cardinal 1	01/09-12/09	0.38	PC, Bit.
Cardinal 2	01/09-12/09	0.46	PC, Bit.
Cardinal 3	01/09-12/09	0.45	PC, Bit.
Muskingum River 5	01/08-12/09	0.60	PC, Bit.
John E Amos	06/09-12/09	0.62	PC, Bit.
Mitchell 1	01/09-12/09	0.59	PC, Bit.
Mitchell 2	01/09-12/09	0.54	PC, Bit.
Weston 4	07/08-12/09	0.48	PC, Sub.
H L Spurlock 4	05/09-12/09	0.67	CFB, Bit.
Wansley 1	02/09-12/09	0.67	PC, Bit.
Wansley 2	01/09-12/09	0.59	PC, Bit.
Nebraska City 2	05/09-12/09	0.60	PC, Sub.
TS Power 1	07/08-12/09	0.49	PC, Sub.

Note: PC = pulverized coal.

CFB = circulating fluidized bed.

Sub = subbituminous coal.

Bit = bituminous coal.

All of the units listed in Table 19 of this preamble have demonstrated 0.70 lb/MWh is achievable. Even though some units are achieving a lower emissions rate, the majority of units listed in Table 19 of this preamble have less than a year of operating data. Proposing a more stringent standard might not provide sufficient compliance margin to account for expected variability in the long term performance of

NO[X] controls. Although not all affected facilities using SCR are currently achieving an emissions rate of 0.70 lb/MWh, all major boiler designs have demonstrated combustion controls that are able to reduce NO[X] emissions to levels where the addition of SCR (or design modifications and operating changes to existing SCR) would allow compliance with a NO[X] emissions rate of 0.70 lb/MWh. We are therefore selecting 88 ng/J (0.70 lb/MWh) as the proposed NO[X] standard for new, modified, and reconstructed units. The range of values we are currently considering for the final rule is 76 to 110 ng/J (0.60 to 0.90 lb/MWh).

Combustion optimization for overall environmental performance is a balance between boiler efficiency, NO[X] emissions, and CO emissions. Although a well operated boiler using combustion controls can achieve a high efficiency and both low NO[X] and CO emissions, the pollutant emissions rates are related. For example, NO[X] reduction techniques that rely on delayed combustion and lower combustion temperatures tend to increase incomplete combustion and result in a corresponding increase in CO emissions. Conversely, high levels of excess air can be used to control CO emissions. However, high levels of excess air increase NO[X] emissions.

The proposed BDT for NO[X] is combustion controls plus the application of SCR. However, there are several approaches an owner/operator could use to comply with an individual NO[X] standard. One approach would be to use combustion controls to minimize the formation of NO[X] to the maximum extent possible and then use a less efficient SCR systems. This tends to result in high CO emissions and significant unburned carbon in the fly ash. From an environmental perspective, we would prefer that

owners/operators select combustion controls that result in slightly higher NO[X] emissions without substantially increasing CO emissions, and use regular efficiency SCR systems. As compared to establishing individual pollutant emission standards, a combined NO[X] plus CO standard accounts for variability in combustion properties and provides additional compliance strategy options for the regulated community, while still providing an equivalent level of environmental protection. In addition, a combined standard provides additional flexibility for owners/operators to minimize carbon and/or ammonia in the fly ash such that the fly ash could still be used in beneficial reuse projects.

In addition, an overly stringent NO[X] standard has the potential to impede the ability of an owner/operator of an EGU from operating at peak efficiency thereby minimizing GHG emissions. A combined standard on the other hand allows owners/operators additional flexibility to operate at or near peak efficiency. A combined standard would also allow the regulated community to work with the local environmental permitting agency to minimize the pollutant of most concern for that specific area. We have previously established a combined NO[X] plus CO combined emissions standard for thermal dryers at coal preparation plants (40 CFR part 60, subpart Y).

To assess the combined NO[X] /CO performance level of EGUs, we requested data from units identified by the 2010 ICR as using certified CO CEMS and achieving the existing NSPS NO[X] standard of 1.0 lb/MWh gross output. We continue to be interested in additional NO[X] and CO certified CEMS data from EGUs and comparable units using that are achieving the existing NSPS NO[X] standard of 1.0 lb/MWh

gross output. Table 20 of this preamble shows the performance of the units identified in our analysis.

Table 20—NO[X]/CO Performance Data

Facility	Time period	Maximum 30-day NO[X] + CO emissions rate (lb/MWh)	Maximum 30-day NO[X]/CO emissions rate (lb/MWh)	Boiler type & primary coal rank
Northside 1	01/05-12/09	1.1	0.89/0.29	CFB, PC.
Northside 2	01/05-12/09	1.1	0.93/0.46	CFB, PC.
Walter Scott, Jr. 4	04/07-12/09	0.95	0.58/0.42	PC, Sub.
WA Parish 5	09/05-12/09	1.1	0.66/0.62	PC, Sub.
WA Parish 6	06/05-12/09	1.2	0.76/0.81	PC, Sub.
WA Parish 7	06/05-12/09	1.8	0.53/1.4	PC, Sub.
WA Parish 8	04/06-12/09	1.5	0.42/1.1	PC, Sub.
HL Spurlock 3	01/09-12/09	1.4	0.83/0.61	CFB, Bit.
HL Spurlock 4	05/09-12/09	1.4	0.67/0.70	CFB, Bit.
TS Power 1	04/08-12/09	0.80	0.49/0.47	PC, Sub.

Note: PC = pulverized coal or petroleum coke.

CFB = circulating fluidized bed.

Sub = subbituminous coal.

Because CO has not historically been a primary pollutant of concern for owners/operators of EGUs, it has not necessarily been a significant factor when selecting combustion control strategies and has not

typically been continuously monitored. Due to the limited availability of CO CEMS data and to account for potential variability we are not aware of, we have concluded it is appropriate in this case to propose a standard with sufficient compliance margin to not inhibit the ability of owner/operators of EGUs to comply with NO[X] specific best available control technology (BACT) requirements or requirements that result from compliance with EPA's proposed Transport Rule. Although 2 of the units shown in Table 21 of this preamble are operating below 1.0 lb/MWh, there are 4 that are operating in the 1.1 to 1.2 lb/MWh range. To provide a compliance margin and to account for situations where NO[X] might be more of a priority pollutant than CO, we are proposing a combined standard of 1.2 lb/MWh. This margin is apparent when comparing the HL Spurlock and Northside units. These fluidized bed boilers use selective non-catalytic reduction (SNCR) to reduce NO[X] emissions. Although the HL Spurlock units perform better in terms of NO[X], the combustion controls result in higher CO and combined NO[X] /CO emission rates. In determining the appropriate combined standard for owner/operators of modified units, we used the data from the WA Parish units. All four of these units have been retrofitted to comply with stringent NO[X] requirements. Owners/operators of modified units could potentially have a more difficult time controlling both NO[X] and CO because the configuration of the boiler cannot be changed. All 4 of the WA Parish units have demonstrated that a standard of 230 ng/J (1.8 lb/MWh) is achievable and we are, therefore, proposing that standard for modified units. We are requesting comment on these standards and are considering a range of 130 to 180 ng/J (1.0 to 1.4 lb/MWh) for new and reconstructed

units and of 180 to 230 ng/J (1.4 to 1.8 lb/MWh) for modified units.

Another potential GHG benefit, beyond boiler efficiency, of a combined NO[X] + CO standard is the flexibility to minimize nitrous oxide (N[2] O) emissions. Formation of N[2] O during the combustion process results from a complex series of reactions and is dependent upon many factors. Operating factors impacting N[2] O formation include combustion temperature, excess air, and sorbent feed rate. The N[2] O formation resulting from SNCR depends upon the reagent used, the amount of reagent injected, and the injection temperature. Adjusting any of these factors can impact CO and/or NO[X] emissions, and a combined standard provides an owner/operator the maximum flexibility to reduce overall criteria and GHG emissions. Pulverized coal boilers tend to operate at sufficiently high temperatures so as to not generally have significant N[2] O emissions. On the other hand, fluidized bed boilers operate at lower temperatures and can have measurable N[2] O emissions. However, the fuel flexibility benefit (*i.e.*, the ability to burn coal refuse and biomass) of fluidized bed boilers can help to offset the increase in N[2] O emissions.

4. Commercial Demonstration Permit

The commercial demonstration permit section of the EGU NSPS was included in the original rulemaking in 1979 *(44 FR 33580)* to assure that the NSPS did not discourage the development of new and promising technologies. In the 1979 rule, the Administrator recognized that the innovative technology waiver provisions under CAA section 111(j) are not adequate to encourage certain capital intensive technologies. *(44*

FR 33580.) Under the innovative technology provisions, the Administrator may grant waivers for a period of up to 7 years from the date of issuance of a waiver or up to 4 years from the start of operation of a facility, whichever is less. The Administrator recognized that this time frame is not sufficient for amortization of high-capital-cost technologies. The commercial demonstration permit section established less stringent requirements for initial full-scale demonstration plants that received a permit in order to mitigate the potential impact of the rule on emerging technologies and insure that standards did not preclude the development of such technologies.

The authority to issue these permits was predicated on the DC Circuit Court's opinion in *Essex Chemical Corp. v. Ruckelshaus, 486 F. 2d 42 (DC Cir. 1973);* NSPS should be set to avoid unreasonable costs or other impacts. Standards requiring a high level of performance, such as the proposed standards for PM, SO[2], and NO[X], might discourage the continued development of some new technologies. Owners/operators may view it as too risky to use new and untried or unproven technologies that have the potential to achieve greater continuous emission reductions than those required to be achieved under the new standards or achieve those reductions at a reduced cost. Thus, to encourage the continued development of new technologies that show promise in achieving levels of performance comparable to those of existing technologies, but at lower cost or with other offsetting environmental or energy benefits, special provisions are needed which encourage the development and use of new technologies, while ensuring that emissions will be minimized.

To mitigate the potential impact on emerging technologies, EPA is proposing to maintain similar standards to those finalized in 2006 for demonstration plants using innovative technologies. This should insure that the amended standards do not preclude the development of new technologies and should compensate for problems that may arise when applying them to commercial-scale units. Under the proposal, the Administrator (in consultation with DOE) would issue commercial demonstration permits for the first 1,000 MW of full-scale demonstration units of pressurized fluidized bed technology and EGUs using a multi-pollutant pollution control technology. Owners/operators of these units that are granted a commercial demonstration permit would be exempt from the amended standards and would instead be subject to less stringent emission standards. The proposed commercial demonstration permit standards for SO[2] and NO[X] are similar to those finalized in 2006 and would avoid weakening existing standards while providing flexibility for innovative and emerging technologies. As discussed earlier, the proposed total PM standard of 0.034 lb/MMBtu approximates an equivalent stringency as the 2006 filterable PM standard of 0.015 lb/MMBtu. In addition, the first 1,000 MW of equivalent electrical capacity using advanced combustion controls to reduce NO[X] emissions would be subject to an emissions standard of 1.0 lb/MWh (or 1.4 (lb NO[X] + CO)/MWh).

The reason we selected these particular technologies is as follows. Multi-pollutant controls (*e.g.*, the Airborne Process (TM), the CEFCO process, Eco Power's COMPLY 2000, Powerspan's ECO(R), ReACT (TM), Skyonic's SkyMine(R), TOPSOE SNOX (TM), and the Pahlman process technology developed by Enviroscrub) offer the potential of reduced compliance

costs and improved overall environmental performance. In addition, for boilers with exhaust temperatures that are too low for SCR (i.e., fluidized bed boilers) multi-pollutant controls are an alternative to SNCR. As discussed above, the use of SNCR can increase N[2] O emissions. Since multi-pollutant controls use a different mechanism to reduce NO[X] emissions, they do not necessarily result in additional N[2] O formation. However, guaranteeing that the technologies could achieve the proposed standards on a continuous basis might discourage the deployment and demonstration of these technologies at EGUs. Pressurized fluidized bed technology has the potential to improve the efficiency and reduce the environmental impact of using coal to generate electricity. However, it is still a relatively undeveloped technology and has only been deployed on a limited basis worldwide. Allowing new pressurized beds to demonstrate compliance with slightly less stringent standards will help assure the NSPS does not discourage the development of this technology. Advanced combustion controls allow for the possibility of developing EGUs with low NO[X] emissions while minimizing the need to install and operate SNCR or SCR. Advanced combustion controls reduce compliance costs, parasitic energy requirements, and ammonia emissions. Allowing the Administrator to approve commercial demonstration permits would limit regulatory impediments to improvements in combustion controls. If the Administrator subsequently finds that a given emerging technology (taking into consideration all areas of environmental impact, including air, water, solid waste, toxics, and land use) offers superior overall environmental performance, alternative standards could then be established by the Administrator. Technologies considered as nothing

more than modified versions of existing demonstrated technologies will not be viewed as emerging technologies and will not be approved for a commercial demonstration permit. We are requesting comment on additional technologies that should be considered and the maximum magnitude of the demonstration permits.

5. Other Exemptions

Because filterable PM emissions are generally negligible for boilers burning natural gas or low sulfur oil, eliminating the PM standard for owners/operators of natural gas and low sulfur oil-fired EGUs would both help harmonize the various steam generating unit NSPS and lower the compliance burden without increasing emissions. Similarly, eliminating the opacity standard for owners/operators of natural gas-fired EGUs would reduce testing and monitoring requirements that do not result in any emissions benefit.

As municipal solid waste (MSW) combustors and CISWI units increase in size it is possible that they could generate sufficient electricity to become subject to the EGU NSPS. We have concluded that it is more appropriate to regulate these units under the CAA section 129 regulations and are, therefore, proposing to exempt owners/operators of affected facilities subject to the standards of performance for large MSW combustors (40 CFR part 60, subpart Eb) and CISWI (40 CFR part 60, subpart CCCC) from complying with the otherwise applicable standards for pollutants that those subparts address. The PM, SO[2], and NO[X] standards in 40 CFR part 60, subpart Eb, are averaged over a daily basis and the PM, SO[2], and NO[X] standards in 40 CFR part 60, subpart CCCC, do not require CEMS and are based on performance test

data. The standards are either approximately equivalent to or more stringent than the present standards in 40 CFR part 60, subpart Da, so this proposed amendment would simplify compliance for owner/operators of MSW combustors and CISWI without an increase in emissions.

Similarly, in the final 2007 steam generating unit amendments *(72 FR 32,710)* we inadvertently expanded the applicability of 40 CFR part 60, subpart Db, to include industrial boilers combusting black liquor and distillate oil at Kraft pulp mills. Even though the distillate oil is generally low sulfur and would otherwise be exempt from the PM standards in 40 CFR part 60, subpart Db, the boilers use ESPs and the addition of "not using a post-combustion technology (except a wet scrubber) to reduce SO[2] or PM emissions" to the oil-fired exemption inadvertently expanded the applicability to owners/operators of boilers currently subject to the standards of performance for Kraft pulp mills (40 CFR part 60, subpart BB). Because 40 CFR part 60, subpart BB, includes a PM standard, we have concluded it is more appropriate to only regulate PM emissions from these units under 40 CFR part 60, subpart BB, and are, therefore, proposing to exempt these units from the PM standard under 40 CFR part 60, subpart Db. The PM standard in 40 CFR part 60, subpart BB, is approximately equivalent in stringency to the one in 40 CFR part 60, subpart Db, prior to the recent amendments, so this proposed amendment would simplify compliance for owner/operators of Kraft pulp mills without an increase in emissions.

We are also proposing to exempt owners/operators of IBs that meet the applicability requirements and that are complying with the SO[2] standard in 40 CFR

part 60, subpart Ja (standards of performance for petroleum refineries) from complying with the otherwise applicable SO[2] limit in 40 CFR part 60, subpart Db. The SO[2] standard in 40 CFR part 60, subpart Ja, is more stringent than in 40 CFR part 60, subpart Db, so this proposed amendment would simplify compliance for owner/operators of petroleum refineries without an increase in pollutant emissions.

C. Changes to the Affected Facility

The present definition of a steam generating unit under 40 CFR part 60, subpart Da, starts at the coal bunkers and ends at the stack breeching. It includes the fuel combustion system (including bunker, coal pulverizer, crusher, stoker, and fuel burners, as applicable), the combustion air system, the steam generating system (firebox, boiler tubes, *etc.*), and the draft system (excluding the stack). This definition works well for traditional coal-fired EGUs, but does not account for potential efficiency improvements that have become available since 40 CFR part 60, subpart Da, was originally promulgated and are recognized through the use of output-based standards.

The proposed rule revision to include integrated CTs and/or fuel cells in the definition of a steam generating unit would increase compliance flexibility and decrease costs. Although we are not aware of any EGUs that have presently integrated either device, using exhaust heat for reheating or preheating boiler feedwater, preheating combustion air, or using the exhaust directly in the boiler to generate steam has high theoretical incremental efficiencies. In addition, using exhaust heat to reheat boiler feedwater would minimize the steam otherwise extracted from the steam turbine used for the reheating process and

increase the theoretical electric output for an equivalent sized boiler. Because the exhaust from either an integrated CT or fuel cell would likely not be exhausted through the primary boiler stack, we are requesting comment on the appropriate emissions monitoring for these separate stacks. Because these emissions would likely be relatively small compared to the boiler, we are considering allowing emissions to be estimated using procedures that are similar to those used in the acid rain trading programs as an alternative to an NO[X] CEMS. The CT or fuel cell emissions and electric output would be added to the boiler/steam turbine outputs.

D. Additional Proposed Amendments

Petroleum Coke. Petroleum coke, a carbonaceous material, is a by-product residual from the thermal cracking of heavy residual oil during the petroleum refining process and is a potentially useful boiler fuel. It has a superior heating value and lower ash content than coal and has historically been priced at a discount compared to coal. However, depending on the original crude feedstock, it may contain greater concentrations of sulfur and metals. At the time 40 CFR part 60, subpart Da, was originally promulgated, petroleum coke was not considered to be "created for the purpose of creating useful heat" and, hence, was not considered a "fossil fuel." However, we have concluded that because petroleum coke has similar physical characteristics to coal, owners/operators of EGUs burning petroleum coke can cost effectively achieve the proposed standards. Due to the increased use of heavier crudes and more efficient processing of refinery residuals, U.S. and worldwide production of petroleum coke is increasing and is expected to continue to grow. Therefore, we expect owners/

operators of EGUs to increase their use of petroleum coke in the future. Consistent with the EGU NESHAP, we are proposing to add petroleum coke to the definition of petroleum.

We are requesting comment on whether petroleum coke should be added to the definition of coal instead of petroleum. Both 40 CFR part 60, subparts Db and Dc, the large and small IB NSPS, include petroleum coke under the definition of coal. Including petroleum coke under coal would be consistent with the IB NSPS. However, the proposed emission standards are fuel neutral and because the revised definition would only apply to affected facilities that begin construction, modification, or reconstruction after the proposal date the impact on the regulated community would be the same if we added petroleum coke to the definition of coal as it would if we added it to the definition of petroleum.

Continuous Opacity Monitoring Systems (COMS). We have concluded that a BLDS and an ESP predictive model provide sufficient assurance that the filterable PM control device is operating properly such that a COMS is no longer necessary. Allowing this flexibility across the various steam generating unit NSPS would increase flexibility and decrease compliance costs without reducing environmental protection.

Titles of 40 CFR part 60, subparts D and Da. We are proposing to simplify the titles, but not amending the applicability, of 40 CFR part 60, subparts D and Da. The end of the titles "for Which Construction Is Commenced After August 17, 1971" and "for Which Construction is Commenced After September 18, 1978" respectively are unnecessary and potentially confusing.

E. Request for Comments on the Proposed NSPS Amendments

We request comments on all aspects of the proposed amendments. All significant comments received will be considered in the development and selection of the final amendments. We specifically solicit comments on additional amendments that are under consideration. These potential amendments are described below.

Net Output. The current output-based emission limit for PM, SO[2], and NO[X] uses gross output, and the proposal includes standards that are based on gross energy output. In general, about 5 percent of station power is used internally by parasitic energy demands, but these parasitic loads vary on a source-by-source basis. To provide a greater incentive for achieving overall energy efficiency and minimizing parasitic loads, we would prefer to base output-based standards on net-energy output. However, it is our understanding that requiring a net output approach could result in monitoring difficulties and unreasonable monitoring costs at modified units. Demonstrating compliance with net-output based standards could be particularly problematic at existing units with both affected and unaffected facilities and units with common controls and/or stacks. Monitoring net output for new and reconstructed units can, on the other hand, be designed into the facility at low costs. To recognize the environmental benefit of overall environmental performance, we are considering establishing a net output-based emission standards for new and reconstructed units in the final rule in lieu of gross output-based standards.

In addition to recognizing the environmental benefit of minimizing the internal parasitic energy demand generally, net output based standards would serve to

further recognize the environmental benefits of the use of supercritical steam conditions because parasitic loads tend to be lower for units using supercritical steam conditions compared to subcritical steam conditions. Furthermore, although the gross efficiencies of IGCC units are projected to be several percentage points higher than a comparable PC facility using supercritical steam conditions, the parasitic energy demands at IGCC units are expected to be much higher at approximately 15 percent. Consequently, on a net output basis, the efficiencies are comparable. Because we do not have continuous net output data available, we are considering assuming 5 percent parasitic losses to convert the gross output values to net output. We are requesting comments on the appropriate conversion factor.

Combined Heat and Power. We are requesting comment on whether it is appropriate to recognize the environmental benefit of electricity generated by CHP units by accounting for the benefit of on-site generation which avoids losses from the transmission and distribution of the electricity. Actual line losses vary from location to location, but if we adopt this provision in the final rule, we are considering a benefit of 5 percent avoided transmission and distribution losses when determining the electric output for CHP units. To assure that only well balanced units would be eligible; this provision would be restricted to units where the useful thermal output is at least 20 percent of the total output.

Opacity. We are requesting comment on the appropriate opacity monitoring procedures for owners/operators of affected facilities that are subject to an opacity standard but are not required to install a COMS. The present monitoring requirements as

amended on January 20, 2011 *(76 FR 3,517)* require Method 9 performance testing every 12 months for owners/operators of affected facilities with no visible emissions, performance testing every 6 months for owners/operators of affected facilities with maximum opacity readings of 5 percent of less, performance testing every 3 months for owners/operators of affected facilities with maximum opacity readings of between 5 to 10 percent, and performance testing every 45 days for owners/operators of affected facilities with maximum opacity readings of greater than 10 percent. We are requesting comment on revising the schedule to require owners/operators of affected facilities with maximum opacity readings of 5 percent or less to conduct annual performance testing. To further reduce the compliance burden for owners/operators of affected facilities that intermittently use backup fuels with opacity of 5 percent or less (*i.e.*, natural gas with distillate oil backup), we are requesting comment on allowing Method 9 performance testing to be delayed until 45 days after the next day that a fuel with an opacity standard is combusted. The required performance testing for owners/operators of affected facilities with maximum opacity readings between 5 to 10 percent would be required to be performed within 6 months. The required performance testing for owners/operators of affected facilities with maximum opacity readings greater than 10 percent would be required to be performed within 3 months. In addition, the alternate Method 22 visible observation approach requires 30 operating days of no visible emissions to qualify for the reduced monitoring procedures. We are requesting comment on only requiring either 5 or 10 days of observation with no visible emissions to qualify for the reduced periodic monitoring.

In general, the level of filterable PM emissions and the resultant opacity from oil-fired steam generating units is a function of the completeness of fuel combustion as well as the ash content in the oil. Distillate oil contains negligible ash content, so the filterable PM emissions and opacity from distillate oil-fired steam generating units are primarily comprised of carbon particles resulting from incomplete combustion of the oil. Naturally low sulfur crude oil and desulfurized oils are higher quality fuels and exhibit lower viscosity and reduced asphaltene, ash, and sulfur content, which result in better atomization and improved overall combustion properties. To provide additional flexibility and decrease the compliance burden on affected facilities, we are requesting comment on whether the opacity standard should be eliminated for owners/operators of affected facilities burning ultra low sulfur (*i.e.*, 15 ppm sulfur) distillate oil.

We are also requesting comment on amending the opacity requirements for owners/operators of affected facilities using PM CEMS, but not complying with the PM standard under 40 CFR part 60, subpart Da. Owners/operators of these facilities are subject to an opacity standard and are required to periodically monitor opacity. We are requesting comment on the appropriateness of waiving all opacity monitoring for owners/operators of these affected facilities. In addition, we are also requesting comment on allowing owners/operators of 40 CFR part 60, subpart D, affected facilities that opt to comply with the 40 CFR part 60, subpart Da, PM standard and qualify for the corresponding opacity exemption to opt back out. (Under the existing rule, once a 40 CFR part 60, subpart D, affected facility opts to comply with the 40 CFR part 60, subpart Da, PM standard in order to

qualify for the corresponding opacity exemption, it cannot subsequently opt to go back to complying with the 40 CFR part 60, subpart D, PM standard.) Finally, we are requesting comment on the appropriateness of eliminating the opacity standard for owners/operators of 40 CFR part 60, subpart D, affected facilities using PM CEMS even if they are not complying with the 40 CFR part 60, subpart Da, PM standard. Consistent with paragraph *40 CFR 60.11(e)*, as long as these facilities demonstrate continuous compliance with the applicable PM standard on a 3-hour average, the opacity standard would not apply.

In addition, we are requesting comment on eliminating the opacity standard for owners/operators of affected facilities complying with a total PM standard of 15 ng/J (0.034 lb/MMBtu) or less that use control equipment parameter monitoring or some other continuous monitoring approach to demonstrate compliance with that standard. Based on the PM performance test data collected as part of the 2010 ICR, at this total PM emissions rate the filterable portion is expected to be significantly lower than the original 40 CFR part 60, subpart Da, filterable PM standard, 0.030 lb/MMBtu. As described in the 2006 NSPS amendments, at filterable PM emissions at this level, opacity is less useful and eliminating the standards would simplify compliance without decreasing environmental protection.

IGCC Units. We are requesting comment on whether an IGCC unit that co-produces hydrocarbons or hydrogen should be subject to the CT NSPS instead of the EGU NSPS. The original rationale for including IGCC units in the EGU NSPS is that it is simply another process for converting coal to electricity. However, an IGCC that co-produces hydrocarbons or

hydrogen would convert a substantial portion of the original energy in the coal to useful chemicals instead of to measurable useful electric and thermal output. Using net-output based standards in this situation would be difficult because a portion of the parasitic load would be attributed to the production of the useful chemicals and it would not be possible to apportion this easily. To avoid owners/operators from producing a small amount of hydrocarbons/hydrogen to avoid being subject to 40 CFR part 60, subpart Da, we are requesting comment on the percentage of coal that must be converted to useful chemical products to quality for regulation under the stationary CT NSPS. We are presently considering between 10 to 20 percent. We are also requesting comment on whether there is a way to effectively account for the parasitic losses such attributable to production of the useful chemicals.

Elimination of Existing References. To simplify compliance and improve the readability of 40 CFR part 60, subpart Da, we are requesting comment on deleting the "emergency condition" requirement for the SO[2] standard exemption, references to percent reductions for NO[X] and PM, references to solvent refined coal, and the existing commercial demonstration permit references. The emergency condition requirement was originally included in 40 CFR part 60, subpart Da, as an alternative to excluding periods of malfunction. The provision was intended to avoid power supply disruptions while also minimizing operation of affected facilities without operation of SO[2] controls. However, the reliability of FGD technology has been demonstrated since 40 CFR part 60, subpart Da, was originally promulgated and malfunctions are uncommon events. Furthermore, the Transport Rule provides a financial incentive to

operate SO[2] control equipment at all times. Therefore, we would delete references to the emergency condition requirement and simply exclude periods of malfunction from the SO[2] standard for owners/operators of affected facilities presently subject to 40 CFR part 60, subpart Da.

The 1990 CAA amendments removed the requirement that standards be based on a percent reduction. The percent reduction requirements for NO[X] and PM have been superseded by the numerical limits for owners/operators of existing units and deleting these references would improve the readability of the subpart. Similarly, we are not aware of any affected facility burning solvent refined coal or operating under the existing commercial demonstration permit. Because these provisions have been superseded, deleting these references would improve the readability of the subpart.

The IB NSPS currently does not credit fuel pretreatment toward compliance with the SO[2] percent reduction standard unless the fuel pretreatment results in a 50 percent or greater reduction in the potential SO[2] emissions rate and results in an uncontrolled SO[2] emissions rate of equal to less than 0.60 lb/MMBtu. We are requesting comment on whether these restrictions discourage the development and use of cost-effective fuel pretreatment technologies and increase costs to the regulated community. To the extent that this restriction could be eliminated without adversely impacting protection of the environment, we are considering eliminating this restriction. We are also requesting comment on other provisions in the steam generating unit NSPS that could be eliminated to reduce regulatory burden without decreasing environmental protection.

The large IB NSPS (40 CFR part 60, subpart Db) currently includes regulatory language for standards for boilers burning MSW. This language was included to assure the broad applicability of 40 CFR part 60, subpart Db. However, subsequent to the original promulgation of 40 CFR part 60, subpart Db, EPA promulgated specific standards for MWCs and exempted owners/operators of MWCs from 40 CFR part 60, subpart Db. We are requesting comment on deleting all references to MSW in 40 CFR part 60, subpart Db. This would simplify compliance and readability of the rule without increasing emissions to the environment. Owners/operators of these units would still be subject to emission standards under 40 CFR part 60, subpart Db, if they stop burning MSW.

Coal Refuse. The high ash and corresponding low Btu content of coal refuse results in lower efficiencies than comparable coal-fired EGUs. Therefore, we are requesting comment on the environmental impact of subcategorizing coal refuse-fired EGUs and maintaining the existing NO[X] standard of 1.0 lb/MWh (or 1.4 lb [NO[X] + CO]/MWh) for owners/operators of these units.

Temporary Boilers. On occasion, owners/operators of industrial facilities need to bring in temporary boilers for steam production for short-term use while the primary steam boilers are not available. The existing testing and monitoring requirements for IB may not be appropriate for temporary boilers used for less than 30 days. We intend to establish alternate testing and monitoring requirements for owners/operators of temporary IBs and are requesting comment on the appropriate requirements.

IX. Summary of Cost, Environmental, Energy, and Economic Impacts of This Proposed NSPS

In setting the standards, the CAA requires us to consider alternative emission control approaches, taking into account the estimated costs and benefits, as well as the energy, solid waste and other effects. EPA requests comment on whether it has identified the appropriate alternatives and whether the proposed standards adequately take into consideration the incremental effects in terms of emission reductions, energy and other effects of these alternatives. EPA will consider the available information in developing the final rule.

The costs, environmental, energy, and economic impacts are typically expressed as incremental differences between the impacts on owners/operators of units complying with the proposed amendments relative to complying with the current NSPS emission standards (*i.e.,* baseline). However, for EGUs this would not accurately represent actual costs and benefits of the proposed amendments. Requirements of the NSR program often result in new EGUs installing controls beyond what is required by the existing NSPS. In addition, owners/operators of new EGUs subject to the requirements of the Transport Rule will likely elect to minimize operating costs by operating at SO[2] and NO[X] emission rates lower than what is required by the existing NSPS. Finally, the proposed EGU NESHAP PM and SO[2] standards for new EGUs are as stringent as or more stringent than the proposed NSPS amendments, and we have concluded that there are no costs or benefits associated with these amendments. We are requesting comment on this conclusion.

To establish the regulatory baseline for NO[X] emissions, we reviewed annual NO[X] emission rates for

units operating at levels below the existing NSPS NO[X] standard that commenced operation between 2005 and 2008 and that reported both NO[X] emissions and gross electric output data to CAMD. The 2009 average annual NO[X] emissions rate for these units was 0.61 lb/MWh. To account for the variability in performance of presently used NO[X] controls, we concluded that 30-day averages are typically 1/4 to 1/3 higher than annual average emission rates and used 0.80 lb/MWh as the baseline. This represents an approximate 12 percent reduction in the growth of NO[X] emissions from new units that would be subject to the proposed standards. We have concluded that a combined NO[X] /CO standard would have similar impacts because CO controls are based on readily available combustion controls. The additional monitoring costs for a combined standard would include additional CEMS certification because many facilities currently have CO CEMS for operational control.

Although multiple coal-fired EGUs have recently commenced operation and several are currently under construction, no new coal-fired EGUs have commenced construction in either 2009 or 2010. In addition, forecasts of new generation capacity from both the EIA and the Edison Electric Institute do not project any new coal-fired EGUs being constructed in the short term. This is an indication that, in the near term, few new coal-fired EGUs will be subject to the NSPS amendments. Because the use of natural gas in boiler/steam turbine-based EGUs is an inefficient use of natural gas to generate electricity, all new natural gas-fired EGUs built in the foreseeable future will most likely be combined cycle units or CT peaking units and, thus, not subject to 40 CFR part 60, subpart Da, but instead subject to the NSPS for stationary CTs (40 CFR part 60, subpart KKKK). Furthermore,

because of fuel supply availability and cost considerations, we assumed that no new oil-fired EGUs will be built during the next 5 years.

Therefore, we are not projecting that any new, reconstructed, or modified steam generating units would become subject to the proposed amendments over the next 5 years. Even though we are not projecting any impacts from the proposed amendments, in the event a new steam generating units does become subject the proposed amendments we have concluded that the proposed amendments would be appropriate. For more information on these impacts, please refer to the economic impact analysis and technical support documents in the public docket.

X. Impacts of These Proposed Rules

A. What are the air impacts?

Under the proposed Toxics Rule, EPA projects annual HCl emissions reductions of 91 percent in 2015, Hg emissions reductions of 79 percent in 2015, and PM[2.5] emissions reductions of 29 percent in 2015. In addition, EPA projects SO[2] emission reductions of 53 percent, annual NO[X] emissions reductions of 7 percent, and annual CO[2] reductions of 1 percent from the power sector by 2015, relative to the base case. See Table 21.

Table 21—Summary of Power Sector Emissions Reductions (TPY)

	SO[2] (million tons)	NO[X] (million tons)	Mercury (tons)	HCl (thousand tons)	PM[2.5] (thousand tons)	CO[2] (million metric tonnes)
Base Case	3.9	2.0	29	78	286	2,243
Proposed Toxics Rule	1.8	1.9	6	10	202	2,219
Change	-2.1	-0.1	-23.0	-68	-83.2	-24.2

B. What are the energy impacts?

Under the provisions of this proposed rule, EPA projects that approximately 9.9 GW of coal-fired generation (roughly 3 percent of all coal-fired capacity and 1% of total generation capacity in 2015) may be removed from operation by 2015. These units are predominantly smaller and less frequently used generating units dispersed throughout the area affected by the rule. If current forecasts of either natural gas prices or electricity demand were revised in the future to be higher, that would create a greater incentive to keep these units operational.

EPA also projects fuel price increases resulting from the proposed Toxics Rule. Average retail electricity prices are shown to increase in the continental U.S. by 3.7 percent in 2015. This is generally less of an increase than often occurs with fluctuating fuel prices and other market factors. Related to this, the average delivered coal price increases by less than 1 percent in 2015 as a result of shifts within and across coal types.

EPA also projects that electric power sector-delivered natural gas prices will increase by about 1 percent over the 2015-2030 timeframe and that natural gas use for electricity generation will increase by about less than 300 billion cubic feet (BCF) over that horizon. These impacts are well within the range of price variability that is regularly experienced in natural gas markets. Finally, the EPA projects coal production for use by the power sector, a large component of total coal production, will decrease by 20 million tons in 2015 from base case levels, which is less than 2 percent of total coal produced for the electric power sector in that year.

C. What are the compliance costs?

The power industry's "compliance costs" are represented in this analysis as the change in electric power generation costs between the base case and policy case in which the sector pursues pollution control approaches to meet the proposed Toxics Rule HAP emission standards. In simple terms, these costs are the resource costs of what the power industry will directly expend to comply with EPA's requirements.

EPA projects that the annual incremental compliance cost of the proposed Toxics Rule is $ 10.9 billion in 2015 ($ 2007). The annualized incremental cost is the projected additional cost of complying with the proposed rule in the year analyzed, and includes the amortized cost of capital investment and the ongoing costs of operating additional pollution controls, needed new capacity, shifts between or amongst various fuels, and other actions associated with compliance.

End-use energy efficiency can be an important part of a compliance strategy for this regulation. It can reduce the cost of compliance, lower consumer costs,

reduce emissions, and help to ensure reliability of the U.S. power system. Policies to promote end-use energy efficiency are largely outside of EPA's direct control. However this rule can provide an incentive for action to promote energy efficiency. To examine the potential impacts of Federal and state energy efficiency policies, EPA used the Integrated Planning Model (IPM).

An illustrative Energy Efficiency Scenario was developed and run as a sensitivity for both the Base Case and the Toxics Rule Case. The illustrative Energy Efficiency Case assumed adoption of two key energy efficiency policies. First, it assumed that states adopted rate-payer funded energy efficiency programs, such as energy efficiency resource standards, integrated resource planning and demand side management plans. Examples of energy efficiency programs that might be driven by these policies include rebate programs for efficient products and state programs to provide technical assistance and information for energy efficient home retrofits. The electricity demand reduction that could be gained from these programs was taken from work done by Lawrence Berkley National Laboratory (LBNL).[179] Second, the Department of Energy (DOE) provided estimates of the demand reductions that could be achieved from implementation of appliance efficiency standards mandated by existing statutes but not yet implemented (appliance standards that have been implemented are in the base case.) EPA assumed that these policies are used beyond the timeframe of the DOE and LBNL estimates (2035 and 2020 respectively) so that their impacts continue through 2050.

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[179] The Shifting Landscape of Ratepayer Funded Energy Efficiency in the U.S., Galen Barbose *et al.*, October 2009, Lawrence Berkeley National Laboratory, LBNL-2258E.

Table 22 below gives the electricity demand reductions that these two policies would yield.

Table 22—Energy Efficiency Sensitivity Results: Electricity Demand Reductions

(all in TWh)	2009	2012	2015	2020	2030	2040	2050
Ratepayer-funded EE Programs		59	110	174	198	198	198
% of U.S. Demand		1.5%	2.7%	4.1%	4.2%	3.9%	3.6%
Federal Appliance Standards		0	6	52	112	114	124
% of U.S. Demand		0.0%	0.2%	1.2%	2.4%	2.2%	2.2%
Total EE Demand Reductions		59	117	226	310	312	322
% of U.S. Demand		1.5%	2.9%	5.3%	6.6%	6.1%	5.8%
U.S. Electricity Demand (EPA Reference)	3,838	4,043	4,086	4,302	4,703	5,113	5,568
Average Annual Growth Rate (2009 to 20xx)			1.05%	1.04%	0.97%	0.93%	0.91%
Net Demand after EE	3,838	3,984	3,969	4,076	4,392	4,801	5,246
Average Annual Growth Rate (2009 to 20xx)			0.56%	0.55%	0.64%	0.73%	0.77%

As shown, these policies are estimated to result in a moderate reduction in U.S. electricity demand climbing to over five percent by 2020 and averaging over five percent from 2020 to 2050. These reductions lower annual average electricity demand growth (from 2009 historic data) through 2020 relative to the reference forecast from 1.04 percent to 0.55 percent.

The effects of the Energy Efficiency Scenario on the projected total electricity generating costs of the power sector are shown below in Table 23. In this table we see the projected costs in the Base and Toxics Rule Cases with and without energy efficiency.

Table 23—Effect of Energy Efficiency Policy on Generation System Costs

Total costs (billion 2007$)—IPM + Total EE	2015	2020	2030
Base	144	155	200
Base + EE	142	150	190
Toxics Rule	155	165	210
Toxics Rule + EE	153	159	199
1. Increment (Base to Base + EE)	-2	-5	-11
2. Increment (Toxics Rule to Toxics Rule + EE)	-2	-6	-11
3. Increment (Base to Toxics Rule)	11	10	10
4. Increment (Base + EE to Toxics Rule + EE)	11	9	9
5. Increment (Base to Toxics Rule) to (Base + EE to Toxics Rule + EE)	0	-1	-1
6. Increment (Base to Toxics Rule +	9	4	-1

Table 23—Effect of Energy Efficiency Policy on Generation System Costs

Total costs (billion 2007$)—IPM + Total EE EE)	2015	2020	2030

In this analysis, the costs of the energy efficiency policies are treated as a component of the cost of generating electricity and are imbedded in the costs seen in Table 23. The modeling estimated that these energy efficiency policies would reduce the total cost of implementing the rule by billions of dollars. EPA looked at a case in which these energy efficiency policies were in place with and without the Toxics Rule. As Table 23 shows, with or without the Toxics Rule, energy efficiency policies reduce the overall costs to generate electricity. The cost reductions increase over time. When comparing the Toxics Rule Case without energy efficiency to the Toxics Rule Case with energy efficiency, the analysis shows that these energy efficiency policies could reduce overall system costs by $ 2 billion in 2015, $ 6 billion in 2020, and $ 11 billion in 2030.

The energy savings driven by these energy efficiency policies, and corresponding lower levels of demand, translate into reductions in electricity prices. EPA's modeling shows that the Toxics Rule increases retail prices by 3.7 percent, 2.6 percent and 1.9 percent in 2015, 2020 and 2030, respectively, relative to the base case. If energy efficiency policies are implemented, the price increase would be smaller in 2015 when retail prices would increase by 3.3 percent. In 2020 and 2030 the reduced demand for electricity is sufficient to reduce the retail price of electricity relative to the Base Case even with the Toxics Rule. If the Toxics Rule is

implemented with energy efficiency, retail electricity prices decrease by about 1.6 percent in 2020 and by about 2.3 percent in 2030 relative to the Base.[180] The effect on average electricity bills, however, may fall more than these percentages as energy efficiency means that less electricity will be used by consumers of electricity.

In the Energy Efficiency Cases, IPM projects considerably more plant retirements than in the Base and Policy Cases. The Base Case with Energy Efficiency in 2020 shows twice as much capacity retiring, and more than double the capacity of coal plant retirements as the Base Case without energy efficiency. The Toxics Rule would increase the amount of capacity retired over the Base Case by 8 GW. If the energy efficiency policies were imposed as the power sector was taking action to come into compliance, the effect of the Toxics Rule on plant retirements would be greater with an additional 25 GW of retirements in 2020. These results are shown in Table 24 below.

Table 24—Effect of Energy Efficiency on Retirements

Retirements Grand Total & (Coal) (GW)	2015	2020	2030
Base	27 (5)	27 (5)	27 (5)
Base + EE	38 (12)	54 (12)	53 (12)
Toxics Rule	35 (15)	35 (14)	35 (14)
Toxics Rule + EE	47 (25)	60 (24)	60 (24)
1. Increment (Base to Base + EE)	11 (7)	27 (7)	26 (7)

[180] Source: EPA's Retail Electricity Price Model.

Table 24—Effect of Energy Efficiency on Retirements

Retirements Grand Total & (Coal) (GW)	2015	2020	2030
2. Increment (Toxics Rule to Toxics Rule + EE)	11 (10)	25 (10)	24 (10)
3. Increment (Base to Toxics Rule)	9 (10)	8 (9)	8 (9)
4. Increment (Base + EE to Toxics Rule + EE)	9 (13)	6 (12)	6 (12)
5. Increment (Base to Toxics Rule) to (Base + EE to Toxics Rule + EE)	0 (3.0)	-2 (3)	-2 (3)
6. Increment (Base to Toxics Rule + EE)	20 (20)	33 (19)	32 (19)

In effect, the timely adoption and implementation of energy efficiency policies would augment currently projected reserve capacities that are instrumental to assuring system reliability.

The addition of energy efficiency policies during and beyond the Toxics Rule compliance period can result in very modest reductions in air emissions. This is largely due to lower levels of electricity generation. As a result, with energy efficiency policies the Toxics Rule

would achieve reductions of approximately an additional 520 pounds of Hg emissions, an additional 80,000 tons of SO[2], and an additional 110,000 tons of NO[X] in 2020.

Although EPA cannot mandate energy efficiency policies, the positive effects of these policies on the cost of rule to industry and consumers could be a strong incentive to undertake them as a part of an overall compliance strategy.

Table 25 presents estimated breakouts of the cost of reducing certain key pollutants under the Toxics Rule. Because many of the strategies to reduce pollutants are multi-pollutant in nature, it is not possible to create a technology-specific breakout of costs (*e.g.* a baghouse reduces PM[2.5] as well as Hg, it also reduces the cost of using additional sorbents to reduce acid gases or further reduce Hg). Costs were first calculated by using representative unit costs for each control option. These costs were then multiplied by the amount of capacity that employed the given control option. Costs were then pro-rated amongst the pollutants that a given technology reduced. This pro-ration was based on rough estimates of the percentage reduction expected for a given pollutant (*e.g.* because a baghouse alone removes significant amounts of PM[2.5] and has a much smaller Hg reduction, most of the baghouse cost was assigned to PM[2.5,] in the case of ACI (which often includes a baghouse) reductions of Hg and fine PM were similar, therefore costs were prorated more equally). Since total costs from the bottom up calculation did not exactly match our total modeled costs, the pollutant by pollutant costs were then prorated to equal the total model costs.

Table 25—Breakouts of Costs by Control Measure and Pollutant for the Proposed Toxics Rule

		Dry FGD + FF	DSI	FF	ACI	Scrubber upgrade	Waste coal FGD	Total
Total (2007 $ MM)	Capital	1,421	428	1,092	1,498	669	94	5,201
	FOM	252	71	41	45	0	20	431
	VOM	377	1,241	105	627	0	66	2,416
	2015 Annual Capital + FOM + VOM	2,050	1,740	1,238	2,173	669	179	8,048
Cost Share	HCl	29%	56%	0%	0%	52%	29%	
	Hg	10%	0%	10%	51%	0%	10%	
	PM[2.5]	32%	0%	90%	49%	0%	32%	
	SO[2]	29%	44%	0%	0%	48%	29%	
Total Annual Costs, 2015 (2007 $ MM)	HCL	588	979	0	0	347	51	1,965
	Hg	205	0	124	1,106	0	18	1,453
	PM[2.5]	654	0	1,114	1,067	0	57	2,892

Table 25—Breakouts of Costs by Control Measure and Pollutant for the Proposed Toxics Rule

	Dry FGD + FF	DSI	FF	ACI	Scrubber upgrade	Waste coal FGD	Total
SO[2]	603	761	0	0	322	53	1,739
TOTAL	2,050	1,740	1,238	2,173	669	179	8,048

	Capital + FOM + VOM Costs	Fuel cost	Total cost	Share of total cost
Acid Gasses (HCl + HCN + HF)	1,965	1,064	3,029	24%
Hg	1,453	825	2,277	18%
PM[2.5]	2,892	357	3,249	36%
SO[2]	1,739	645	2,384	22%
Total	8,048	2,892	10,940	100%

	Capital share	Tons reduced	$/ton ($/lb for Hg)	General range of costs from other MACT rules
Acid Gasses (HCl + HCN + HF)	37%	106,038	$ 18,529	$ 2,500-$ 55,000
Hg	49%	18	$ 40,428	$ 1,250-$ 55,200
PM[2.5]	74%	83,246	$ 34,742	$ 1,600-$ 55,000
SO[2]	44%	2,050,871	$ 848	$ 540-$ 5,100
Total				

D. What are the economic impacts?

For this proposed rule, EPA analyzed the costs using IPM. IPM is a dynamic linear programming model that can be used to examine the economic impacts of air pollution control policies for a variety of HAP and other pollutants throughout the contiguous U.S. for the entire power system.

Documentation for IPM can be found in the docket for this rulemaking or at http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.

EPA also included an analysis of impacts of the proposed rule to industries outside of the electric power sector by using the Multi-Market Model. This model is a partial equilibrium model that includes 100 sectors that cover energy, manufacturing, and service applications and is designed to capture the short-run effects associated with an environmental regulation. It was used to estimate economic impacts for the recently promulgated Industrial Boiler major and area source standards and CISWI standard.

We use the Multi-Market model to estimate the social cost of the proposed rule. Using this model, we estimate the social costs of the proposal to be $ 10.9 billion (2007], which is almost identical to the compliance costs. The usefulness of a Multi-Market model in predicting the estimated effects is limited because the electric power sector affects all sectors of the economy. For the final rule, we will be refining the social cost estimates with general equilibrium models, including an assessment with our upgraded CGE model, EMPAX. Commenters are encouraged to provide other general equilibrium model platforms and to provide other information to refine the social cost assessments for the final rule.

EPA also performed a screening analysis for impacts on small entities by comparing compliance costs to sales/revenues (*e.g.*, sales and revenue tests). EPA's analysis found the tests were typically higher than 1 percent for small entities included in the screening analysis. EPA has prepared an Initial Regulatory Flexibility Analysis (IRFA) that discusses alternative regulatory or policy options that minimize the rule's small entity impacts. It includes key information about key results from the SBAR panel.

Although a stand-alone analysis of employment impacts is not included in a standard cost-benefit analysis, the current economic climate has led to heightened concerns about potential job impacts. Such an analysis is of particular concern in the current economic climate as sustained periods of excess unemployment may introduce a wedge between observed (market) wages and the social cost of labor. In such conditions, the opportunity cost of labor required by regulated sectors to bring their facilities into compliance with an environmental regulation may be lower than it would be during a period of full employment (particularly if regulated industries employ otherwise idled labor to design, fabricate, or install the pollution control equipment required under this proposed rule). For that reason, EPA also includes estimates of job impacts associated with the proposed rule. EPA presents an estimate of short-term employment opportunities as a result of increased demand for pollution control equipment. Overall, the results suggest that the proposed rule could support a net of roughly 31,000 job-years[181] in direct employment impacts in 2015.

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[181] Numbers of job years are not the same as numbers of individual jobs, but represents the amount of work that can be

The basic approach to estimate these employment impacts involved using projections from IPM from the proposed rule analysis such as the amount of capacity that will be retrofit with control technologies, for various energy market implications, along with data on labor and resource needs of new pollution controls and labor productivity from secondary sources, to estimate employment impacts for 2015. For more information, please refer to the TSD for this analysis, "Employment Estimates of Direct Labor in Response to the Proposed Toxics Rule in 2015."

EPA relied to Morgenstern, *et al.* (2002), identify three economic mechanisms by which pollution abatement activities can indirectly influence jobs:

Higher production costs raise market prices, higher prices reduce consumption, and employment within an industry falls ("demand effect");

Pollution abatement activities require additional labor services to produce the same level of output ("cost effect"); and

Post regulation production technologies may be more or less labor intensive (*i.e.*, more/less labor is required per dollar of output) ("factor-shift effect").

Using plant-level Census information between the years 1979 and 1991, Morgenstern, *et al.*, estimate the size of each effect for four polluting and regulated industries (petroleum, plastic material, pulp and paper, and steel). On average across the four industries, each additional $ 1 million spending on

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performed by the equivalent of one full-time individual for a year (or FTE). For example, 25 job years may be equivalent to five full-time workers for five years, 25 full-time workers for one year, or one full-time worker for 25 years.

pollution abatement results in an small net increase of 1.6 jobs; the estimated effect is not statistically significant different from zero. As a result, the authors conclude that increases in pollution abatement expenditures do not necessarily cause economically significant employment changes. The conclusion is similar to Berman and Bui (2001) who found that increased air quality regulation in Los Angeles did not cause large employment changes. [182] For more information, please refer to the RIA for this proposed rule.

The ranges of job effects calculated using the Morgenstern, *et al.*, approach are listed in Table 26.

Table 26—Range of Job Effects for the Electricity Sector

	Estimates using Morgenstern, et al. (2001)		
	Demand effect	Cost effect	Factor shift effect
Change in Full-Time Jobs per Million Dollars of Environmental Expenditure fna	-3.56	2.42	2.68.
Standard Error	2.03	1.35	0.83.
EPA estimate for	-45,000 to +2,500	+4,700 to 24,000	+200 to 32,000.

[182] For alternative views in economic journals, see Henderson (1996) and Greenstone (2002).

Table 26—Range of Job Effects for the Electricity Sector

	Estimates using Morgenstern, et al. (2001)		
	Demand effect	Cost effect	Factor shift effect
Proposed Rule fnb			

fna Expressed in 1987 dollars. See footnote a from Table 9-3 of the RIA for inflation adjustment factor used in the analysis.

fnb According to the 2007 Economic Census, the electric power generation, transmission and distribution sector (NAICS 2211) had approximately 510,000 paid employees.

EPA recognizes there may be other job effects which are not considered in the Morgenstern, *et al.*, study. Although EPA has considered some economy-wide changes in industry output as shown earlier with the Multi-Market model, we do not have sufficient information to quantify other associated job effects associated with this rule. EPA solicits comments on information (*e.g.*, peer-reviewed journal articles) and data to assess job effects that may be attributable to this rule.

E. What are the benefits of this proposed rule?

We estimate the monetized benefits of this proposed regulatory action to be $ 59 billion to $ 140 billion (2007$, 3 percent discount rate) in 2016. The monetized benefits of the proposed regulatory action at a 7 percent discount rate are $ 53 billion to $ 130 billion (2007]. These estimates reflect the economic value of the Hg benefits as well as the PM[2.5] and CO[2] -related co-benefits.

Using alternate relationships between PM[2.5] and premature mortality supplied by experts, higher and lower benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates.[183] A summary of the monetized benefits estimates at discount rates of 3 percent and 7 percent is in Table 27 of this preamble.

Table 27—Summary of the PM[2.5] Monetized Co-Benefits Estimates for the Proposed Toxics Rule in 2016
[Billions of 2007$] fna

	Estimated emission reductions (million tons per year)	Monetized PM[2.5] co-benefits (3% discount rate)	Monetized PM[2.5] co-benefits (7% discount rate)
PM[2.5] Precursors			
SO[2]	2.1	$ 58 to $ 140	$ 53 to $ 130.
Total		$ 58 to $ 140	$ 53 to $ 130.

fna All estimates are for the implementation year (2016), and are rounded to two significant figures. All fine particles are assumed to have equivalent health effects, but the benefit-per-ton estimates vary between precursors because each ton of precursor reduced has a different propensity to form PM[2.5]. Benefits from reducing HAP are not included.

These benefits estimates represent the total monetized human health benefits for populations exposed to less PM[2.5] in 2016 from controls installed to reduce air pollutants in order to meet these standards. These estimates are calculated as the sum of the

[183] Roman *et al.*, 2008. Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S. Environ. Sci. Technol., 42, 7, 2268-2274.

monetized value of avoided premature mortality and morbidity associated with reducing a ton of PM[2.5] and PM[2.5] precursor emissions. To estimate human health benefits derived from reducing PM[2.5] and PM[2.5] precursor emissions, we used the general approach and methodology laid out in Fann, *et al.* (2009).[184]

To generate the benefit-per-ton estimates, we used a model to convert emissions of PM[2.5] precursors into changes in ambient PM[2.5] levels and another model to estimate the changes in human health associated with that change in air quality. Finally, the monetized health benefits were divided by the emission reductions to create the benefit-per-ton estimates. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between precursors because each ton of precursor reduced has a different propensity to form PM[2.5]. For example, SO[X] has a lower benefit-per-ton estimate than direct PM[2.5] because it does not form as much PM[2.5], thus the exposure would be lower, and the monetized health benefits would be lower.

For context, it is important to note that the magnitude of the PM benefits is largely driven by the concentration response function for premature mortality. Experts have advised EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship

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[184] Fann, N., C.M. Fulcher, B.J. Hubbell. 2009. "The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution." Air Qual Atmos Health (2009) 2:169-176.

between PM[2.5] concentrations and premature mortality. For this proposed rule we cite two key empirical studies, one based on the American Cancer Society cohort study[185] and the extended Six Cities cohort study.[186] In the Regulatory Impacts Analysis (RIA) for this proposed rule, which is available in the docket, we also include benefits estimates derived from expert judgments and other assumptions.

This analysis does not include the type of detailed uncertainty assessment found in the 2006 PM[2.5] NAAQS RIA because we lack the necessary air quality input and monitoring data to run the benefits model. However, the 2006 PM[2.5] NAAQS benefits analysis[187] provides an indication of the sensitivity of our results to various assumptions.

It should be emphasized that the monetized benefits estimates provided above do not include benefits from several important benefit categories, including reducing other air pollutants, ecosystem effects, and visibility impairment. The benefits from reducing various HAP have not been monetized in this analysis, including reducing 68,000 tons of HCl, and 3,200 tons of other metals each year. Although we do not have sufficient information or modeling available to provide monetized estimates for this rulemaking, we include a

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[185] Pope *et al.*, 2002. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." Journal of the American Medical Association 287:1132-1141.

[186] Laden *et al.*, 2006. "Reduction in Fine Particulate Air Pollution and Mortality." *American Journal of Respiratory and Critical Care Medicine.* 173: 667-672.

[187] U.S. Environmental Protection Agency, 2006. Final Regulatory Impact Analysis: PM[2.5] NAAQS. Prepared by Office of Air and Radiation. October. Available on the Internet at *http://www.epa.gov/ttn/ecas/ria.html*.

qualitative assessment of the health effects of these air pollutants in the RIA for this proposed rule, which is available in the docket.

Table 28—Summary of the Monetized Benefits, Social Costs, and Net Benefits for the Proposed Rule in 2016

[Millions of 2006$] fna

	3% Discount rate	7% Discount rate
Total Monetized Benefits fnb	$ 59,000 to $ 140,000	$ 53,000 to $ 130,000.
Hg-related Benefits fnc	$ 4.1 to $ 5.9	$ 0.45 to $ 0.89.
CO[2]-related Benefits	$ 570	$ 570.
PM[2.5]-related Co-benefits fnd	$ 59,000 to $ 140,000	$ 53,000 to $ 120,000.
Total Social Costs fne	$ 10,900	$ 10,900.
Net Benefits	$ 48,000 to $ 130,000	$ 42,000 to $ 130,000.
Non-monetized Benefits	Visibility in Class I areas.	
	Cardiovascular effects of Hg exposure.	
	Other health effects of Hg exposure.	
	Ecosystem effects.	
	Commercial and non-freshwater fish consumption.	

fna All estimates are for 2016, and are rounded to two significant figures. The net present value of reduced CO[2] emissions are calculated differently than other benefits. The same discount rate used to discount the value of damages from future emissions (SCC at 5, 3, 2.5 percent) is used to calculate net present value of SCC for internal consistency. This table shows monetized CO[2] co-benefits at discount rates at 3 and 7 percent that were

calculated using the global average SCC estimate at a 3 percent discount rate because the interagency workgroup on this topic deemed this marginal value to be the central value. In section 6.6 of the RIA we also report the monetized CO[2] co-benefits using discount rates of 5 percent (average), 2.5 percent (average), and 3 percent (95th percentile).

fnb The total monetized benefits reflect the human health benefits associated with reducing exposure to MeHg, PM[2.5], and ozone.

fnc Based on an analysis of health effects due to recreational freshwater fish consumption.

fnd The reduction in premature mortalities account for over 90 percent of total monetized PM[2.5] benefits.

fne Social costs are estimated using the MultiMarket model, in order to estimate economic impacts of the proposal to industries outside the electric power sector. Details on the social cost estimates can be found in Chapter 9 and Appendix E of the RIA.

For more information on the benefits and cost analysis, please refer to the RIA for this rulemaking, which is available in the docket.

XI. Public Participation and Request for Comment

We request comment on all aspects of this proposed rule.

During this rulemaking, we conducted outreach to small entities and convened a SBAR Panel to obtain advice and recommendation of representatives of the small entities that potentially would be subject to the requirements of this proposed rule. As part of the SBAR Panel process we conducted outreach with representatives from various small entities that would be affected by this proposed rule. We met with these SERs to discuss the potential rulemaking approaches and potential options to decrease the impact of the rulemaking on their industries/sectors. We distributed outreach materials to the SERs; these materials

included background, project history, CAA section 112 overview, constraints on rulemaking, affected facilities, data, rulemaking options under consideration, potential control technologies and estimated costs, applicable small entity definitions, small entities potentially subject to regulation, and questions for SERs. We met with SERs that will be impacted directly by this proposed rule to discuss the outreach materials and receive feedback on the approaches and alternatives detailed in the outreach packet. The Panel received written comments from the SERs following the meeting in response to discussions at the meeting and the questions posed to the SERs by the Agency. The SERs were specifically asked to provide comment on regulatory alternatives that could help to minimize the rule's impact on small businesses. (See elsewhere in this preamble for further information regarding the SBAR process.)

EPA consulted with state and local officials in the process of developing the proposed action to permit them to have meaningful and timely input into its development. EPA met with 10 national organizations representing state and local elected officials to provide general background on the proposal, answer questions, and solicit input from state/local governments. EPA also consulted with tribal officials early in the process of developing this proposed rule to permit them to have meaningful and timely input into its development. Consultation letters were sent to 584 tribal leaders. The letters provided information regarding EPA's development of NESHAP for EGUs and offered consultation. Three consultation meetings were requested and held. The Unfunded Mandates Reform Act (UMRA) discussion in this preamble includes a description of the consultation. (See elsewhere in this preamble for further information

regarding these consultations with state, local, and tribal officials.)

XII. Statutory and Executive Order Reviews

A. Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Under EO 12866 (*58 FR 51735,* October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $ 100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities.

Accordingly, EPA submitted this action to the OMB for review under EO 12866 and any changes in response to OMB recommendations have been documented in the docket for this action. For more information on the costs and benefits for this rule, please refer to Table 28 of this preamble.

When estimating the human health benefits and compliance costs in Table 28 of this preamble, EPA applied methods and assumptions consistent with the state-of-the-science for human health impact assessment, economics and air quality analysis. EPA applied its best professional judgment in performing this analysis and believes that these estimates provide a reasonable indication of the expected benefits and costs to the nation of this rulemaking. The RIA available in the docket describes in detail the empirical basis for EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. In doing what is laid out above in this paragraph, EPA adheres to EO 13563, "Improving

Regulation and Regulatory Review," *(76 FR 3821,* January 18, 2011), which is a supplement to EO 12866.

In addition to estimating costs and benefits, EO 13563 focuses on the importance of a "regulatory system [that] * * * promote[s] predictability and reduce[s] uncertainty" and that "identify[ies] and use[s] the best, most innovative, and least burdensome tools for achieving regulatory ends." In addition, EO 13563 states that "[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote such coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation." We recognize that the utility sector faces a variety of requirements, including ones under section 110(a)(2)(D) dealing with the interstate transport of emissions contributing to ozone and PM air quality problems, with coal combustion wastes, and with the implementation of section 316(b) of the CWA. They will also soon be the subject of a rulemaking under CAA section 111 concerning emissions of GHG. In developing today's proposed rule, EPA recognizes that it needs to endeavor to approach these rulemakings in ways that allow the industry to make practical investment decisions that minimize costs in complying with all of the final rules, while still achieving the fundamentally important environmental and public health benefits that underlie the rulemakings.

1. Human Health and Environmental Effects Due to Exposure to MeHg

In this section, we provide a qualitative description of human health and environmental effects due to exposure to MeHg. In 2000, the NAS Study was issued

which provides a thorough review of the effects of MeHg on human health (NRC, 2000). Many of the peer-reviewed articles cited in this section are publications originally cited in the MeHg Study. In addition, EPA has conducted literature searches to obtain other related and more recent publications to complement the material summarized by the NRC in 2000.

2. Reference and Benchmark Doses

In 1995, EPA set a health-based ingestion rate for chronic oral exposure to MeHg, termed an oral RfD, at 0.0001 mg/kg-day. The RfD was based on effects reported to children exposed *in utero* during the Iraqi poisoning episode (Marsh, et al., 1987). Subsequent research from large epidemiological studies in the Seychelles, Faroe Islands, and New Zealand added substantially to the body of knowledge on neurological effects from MeHg exposure. Per Congressional direction via the House Appropriations Report for Fiscal Year 1999, the NRC was contracted by EPA to examine these data and, if appropriate, make recommendations for deriving a revised RfD. The NRC's analysis concluded that the Iraqi study on children exposed *in utero* should no longer be considered the critical study for the derivation of the RfD. NRC also provided specific recommendations to EPA for a MeHg RfD based on analyses of the three large epidemiological studies (NRC, 2000). Although derived from a more complete data set and with a somewhat different methodology, the current RfD is numerically the same as the previous (1995) RfD (0.0001 mg/kg-day).

The RfD is an estimate (with uncertainty spanning perhaps an order of magnitude) of a daily exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of

deleterious effects during a lifetime (EPA, 2002). Data published since 2001, development of risk assessment methods, and continued examination of the concepts underlying benchmark doses and RfDs based on them add to EPA's interpretation of the 2001 MeHg RfD in the current rulemaking. Additional information on EPA's interpretation can be found in Section X of the Appropriate & Necessary TSD.

3. Neurologic Effects of Exposure to MeHg

In their review of the literature, the NRC found neurodevelopmental effects to be the most sensitive endpoints and appropriate for establishing an RfD (NRC, 2000). Studies involving animals found sensory effects and support the conclusions reached by studies involving human subjects, with a similar range of neurodevelopmental effects reported (NRC, 2000). As noted by the NRC, the clinical significance of some of the more subtle endpoints included in the human low-dose studies is difficult to gauge due to the quantal nature of the effects observed (*i.e.*, subjects either display the abnormality or do not) and the rather low occurrence rate of these effects.

Little is known about the effects of low-level chronic MeHg exposure in children that can be linked to exposures after birth. The difficulty in identifying a cohort exposed after birth but not prenatally, or separating prenatal from postnatal effects, makes research on the topic complicated. These challenges were present in the three large epidemiologic studies used to derive the RfD, as in all three studies there was postnatal exposure as well.

Several studies have shown neurological effects including delayed peak latencies in brainstem auditory evoked potentials are associated with prenatal or

recent MeHg exposures (Debes, et al., 2006; Grandjean, et al., 1997; Murata, *et al.*, 2004). A recent case control study of Chinese children in Hong Kong (Cheuk and Wong, 2006) paired 59 normal controls with 52 children (younger than 18 years) diagnosed with attention deficit/hyperactivity disorder (ADHD). The authors reported a significant difference in blood Hg levels between cases and controls (geometric mean 18.2 nmol/L (95 percent confidence interval, CI, 15.4-21.5 nmol/L] vs. 11.6 nmol/L [95 percent CI 9.9-13.7 nmol/L], $p < 0.001$), which persisted after they adjusted for age, gender and parental occupational status (p less than 0.001).

Several studies have also examined the effects of chronic low-dose MeHg exposures on adult neurological and sensory functions (*e.g.*, Lebel, *et al.*, 1996; Lebel, *et al.*, 1998; Beuter and Edwards, 1998). Research results suggest that elevated hair MeHg concentrations in individuals are associated with visual deficits, including loss of peripheral vision and chromatic and contrast sensitivity. These concentrations range between a high of 50 ppm, and possibly as low as 20 ppm, although a no observed adverse effect level (NOAEL) was not clearly estimated). These individuals also exhibited a loss of manual dexterity, hand-eye coordination, and grip strength; difficulty performing complex sequences of movement; and (at the higher doses) tremors, although expression of some effects was sex-specific. Although additional data would be needed to quantify a dose-response relationship for these effects, it is noteworthy that the effects occurred at doses lower than the Japanese and Iranian poisoning episodes, via consumption of Hg-laden fish in riverine Brazilian communities. These are areas where extensive Hg contamination has resulted from small-scale gold mining activities begun

in the 1980s. Note that these doses are above the EPA's RfD equivalent level for hair Hg. In regard to the Lebel, et al. (1998) study, the NRC states that "the mercury exposure of the cohort is presumed to have resulted from fish-consumption patterns that are stable and thus relevant to estimating the risk associated with chronic, low-dose MeHg exposure" (NRC, 2000). The NRC noted, however, "that the possibility cannot be excluded that the neurobehavioral deficits of the adult subjects were due to increased prenatal, rather than ongoing, MeHg exposure." More recent studies in the Brazilian communities provide some evidence that the adverse neurobehavioral effects may in fact result from postnatal exposures (*e.g.*, Yokoo, *et al.*, 2003); however, additional longitudinal study of these and other populations is required to resolve questions regarding exposure timing and fully characterize the potential neurological impacts of MeHg exposure in adults.

4. Cardiovascular Impacts of Exposure to MeHg

A number of epidemiological and toxicological studies have evaluated the relationship between MeHg exposures and various cardiovascular effects including acute myocardial infarction (AMI), oxidative stress, atherosclerosis, decreased heart rate variability (HRV), and hypertension. An AMI (*i.e.*, heart attack) is clearly an adverse health effect. The other four effects are considered "intermediary" effects and risk factors for development of AMI or coronary heart disease. Hypertension is a commonly measured clinical outcome that is also considered a risk factor for other adverse effects (such as stroke).

These epidemiological studies evaluated Hg exposures using various measures (including Hg or MeHg in blood, cord blood, hair and toenails) and the

associations of these exposures with various effects. The overall results of the available studies (published before and after NRC 2000) are summarized in the following paragraphs.

Studies in two cohorts (the Kuopio Ischemic Heart Disease Risk Factor study, or KIHD study; and the European Community Multicenter Study on Antioxidants, Myocardial Infarction and Breast Cancer, or EURAMIC study), report statistically significant positive associations between MeHg exposure and AMI. A third study (U.S. Health Professionals Study, USHPS) also reported a positive association between Hg exposure and AMI but only after excluding individuals who may have been occupationally exposed to inorganic Hg. However, a fourth study (the Northern Sweden Health and Disease Study, or NSHDS) reported an inverse relationship between MeHg exposure and AMI, and another study (Minamata Cohort) identified no increase in fatal heart attacks following a MeHg poisoning epidemic.

Although each of these AMI studies had strengths and limitations, the EURAMIC and KIHD studies appear to be most robust. Strengths of these two studies include their large sample sizes and control for key potential confounders (such as exposure to omega-3 fatty acid, which are related to decreases in cardiovascular effects). The KIHD study was well-designed and included a population-based recruitment and limited loss to follow-up. Additional strengths of the EURAMIC study include exposure data that were collected shortly after the AMI. In addition, recruitment of participants across nine countries likely resulted in a wide range of MeHg and fish fatty acid intakes. Although the USHPS study was well-conducted, the Hg exposure measure used was

potentially confounded by possible inorganic Hg exposures in roughly half of the study population. When these subjects were excluded from the analyses, the power of the study to detect an effect was reduced. Limitations of the NSHDS study included its relatively small sample size and narrow MeHg exposure range. The Minamata study also had important limitations, primarily that the effects of the very high exposures in this population may differ substantially from effects of lower exposures expected at typical environmental levels; also the death certificates were collected starting 10 years after the initial cases of MeHg poisoning.

In summary, the most robust available studies (*i.e.*, the EURAMIC and KIHD), report statistically significant positive relationships between MeHg exposure and the incidence of AMI. Further, both studies report statistically significantly positive trend tests for the relationship between MeHg and AMI. The USHPS provides some additional evidence of a positive association. The NSHDS and the Minamata Cohort studies are less robust; however, the results from those two studies showed no adverse effect, and, therefore, reduce the overall confidence in the association of MeHg with AMIs.

The studies that evaluated intermediary effects generally provide some additional evidence of the potential adverse effects of Hg or MeHg to the cardiovascular system. However, results are somewhat inconsistent. For example, two epidemiological studies (the KIHD and the Tapajos River Basin studies) reported positive associations between MeHg exposures and oxidative stress, but one short-term study (the Quebec Sport Fisherman Study) reported a negative association. For atherosclerosis, the results

across epidemiological studies are more consistent. Three studies (the KIHD, Faroese Whaler Cohort Study, and Nunavik Inuit Cohort in Quebec) reported a positive association between MeHg exposure and atherosclerosis. Moreover, animal studies and *in vitro* studies (cell studies) provide additional evidence that MeHg may cause oxidative stress and increased risk of atherosclerosis.

Another intermediary effect, decreases in heart rate variability (HRV), can be indicative of cardiovascular disease, particularly in the elderly. Associations of decreased HRV with increased MeHg exposures have been reported in four of five studies of adults and three studies of children; however, the clinical significance of decreased HRV in children is not known.

The existing epidemiological studies are inconsistent in showing an association between MeHg and hypertension. A prospective study of the Faroe Islands birth cohort reported statistically significant associations between elevated cord blood Hg levels or maternal hair Hg levels and increased diastolic and systolic blood pressures for 7-year-old children; this association was no longer seen in the children tested at 14 years. Other studies suggest that these are not correlated.

In January 2010, EPA sponsored a workshop in which a group of experts were asked to assess the plausibility of a causal relationship between MeHg exposure and cardiovascular health effects, and to advise EPA on methodologies for estimating population-level cardiovascular health impacts of reduced MeHg exposure. The final workshop report was published in January, 2011, and includes as its key recommendation the development of a dose-response function relating MeHg exposure and AMI

incidence for use in regulatory benefits analyses that target Hg air emissions.

The experts identified both intermediary and clinical effects in the published literature. The panelists assessed the strength of evidence associated with three intermediary effects (*i.e.*, oxidative stress, atherosclerosis, and HRV), and with two main clinical effects (*i.e.*, hypertension and AMI). The panel concluded there was at least moderate evidence of an association between MeHg exposure and all of these effects in the epidemiological literature. The evidence for an association with hypertension was considered the weakest.

The workshop panel concluded that "a causal link between MeHg and AMI is plausible, given the range of intermediary effects for which some positive evidence exists and the strength and consistency across the epidemiological studies for AMI." During the workshop, the individual experts provided quantitative estimates of the likelihood of a true causal relationship between MeHg and AMI, ranging from 0.45 to 0.80, and characterized by the panel as "moderate to strong." A recently published health benefits analysis of reduced MeHg exposures analyzed the epidemiology literature and assessed the "plausibility of causal interpretation of cardiovascular risk" as about 1/3 as a separate parameter in their analysis.

EPA did not develop a quantitative dose-response assessment or quantified estimates of benefits for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects. In addition, there is inconsistency among available studies as to the association between MeHg exposure

and various cardiovascular system effects. The pharmacokinetics of some of the exposure measures (such as toenail Hg levels) are not well understood. The studies have not yet received the review and scrutiny of the more well-established neurotoxicity data base.

5. Genotoxic Effects of Exposure to MeHg

The Mercury Study noted that MeHg is not a potent mutagen but is capable of causing chromosomal damage in a number of experimental systems. The NRC concluded that evidence that human exposure to MeHg caused genetic damage is inconclusive; they note that some earlier studies showing chromosomal damage in lymphocytes may not have controlled sufficiently for potential confounders.) One study of adults living in the Tapajos River region in Brazil (Amorim, et al., 2000) reported a direct relationship between MeHg concentration in hair and DNA damage in lymphocytes,; polyploidal aberrations and chromatid breaks observed at Hg hair levels around 7.25 ppm and 10 ppm, respectively. Long-term MeHg exposures in this population were believed to occur through consumption of fish, suggesting that genotoxic effects (largely chromosomal aberrations) may result from dietary, chronic MeHg exposures similar to and above those seen in the Faroes and Seychelles populations.

6. Immunotoxic Effects to Exposure to MeHg

Although exposure to some forms of Hg can result in a decrease in immune activity or an autoimmune response (ATSDR, 1999), evidence for immunotoxic effects of MeHg is limited (NRC, 2000). Some persistent immunotoxic effects have been observed in mice treated with MeHg in drinking water at relatively high levels of exposure (Havarinasab, *et al.*, 2007). A

recent study of fish-consuming communities in Amazonian Brazil has identified a possible association between MeHg exposure and immunotoxic effects reflective of autoimmune dysfunction. The authors noted that this may reflect interactions with infectious disease and other factors (Silva, *et al.*, 2004). Exposures to these communities occurred via fish consumption (some community members were also exposed to inorganic Hg through gold mining activities). The researchers assessed levels of specific antibodies that are markers of Hg-induced auto-immunity. They found that both prevalence and levels of these antibodies were higher in a population exposed to MeHg via fish consumption compared to a reference (unexposed) population. Median hair Hg concentration was 8 ppm in the more exposed population (range 0.29 to 58.47 ppm) and 5.57 ppm in the less exposed reference population (range 1.19 to 16.96 ppm). The ranges of Hg hair concentrations reported in this study are within an order of magnitude of the concentration corresponding to the MeHg RfD. Overall, there is a relatively small body of evidence from human studies that suggests exposure to MeHg can result in immunotoxic effects.

7. Other Hg-Related Human Toxicity Data

Based on limited human and animal data, MeHg is classified as a "possible" human carcinogen by the IARC (1994) and in the IRIS (EPA, 2002). The existing evidence supporting the possibility of carcinogenic effects in humans from low-dose chronic exposures is tenuous. Multiple human epidemiological studies have found no significant association between Hg exposure and overall cancer incidence, although a few studies have shown an association between Hg exposure and specific types of cancer incidence (*e.g.*,

acute leukemia and liver cancer; NRC, 2000). The Mercury Study observed that "MeHg is not likely to be a human carcinogen under conditions of exposure generally encountered in the environment" (p 6-16, Vol. V). This was based on observation that tumors were noted in one species only at doses causing severe toxicity to the target organ. Although some of the human and animal research suggests that a link between MeHg and cancer may plausibly exist, more research is needed.

There is also some evidence of reproductive and renal toxicity in humans from MeHg exposure. For example, a smaller than expected number of pregnancies were observed among women exposed via contaminated wheat in the Iraqi poisoning episode of 1956 (Bakir, *et al.,* 1973); other victims of that same poisoning event exhibited signs of renal damage (Jalili and Abbasi, 1961); and an increased incidence of deaths due to kidney disease was observed in women exposed in Minamata Bay via contaminated fish (Tamashiro, *et al.,* 1986). Other data from animal studies suggest a link between MeHg exposure and similar reproductive and renal effects, as well as hematological toxicity (NRC, 2000). Overall, human data regarding reproductive, renal, and hematological toxicity from MeHg are very limited and are based on either studies of the two high-dose poisoning episodes in Iraq and Japan or animal data, rather than epidemiological studies of chronic exposures at the levels of interest in this analysis. Note that the Mercury Study provides an assessment of MeHg cancer risk using the 1993 version of the Revised Cancer Guidelines.

8. Ecological Effects of Hg

Deposition of Hg to watersheds can also have an impact on ecosystems and wildlife. Mercury contamination is present in all environmental media with aquatic systems experiencing the greatest exposures due to bioaccumulation. Bioaccumulation refers to the net uptake of a contaminant from all possible pathways and includes the accumulation that may occur by direct exposure to contaminated media as well as uptake from food. In the sections that follow, numerous adverse effects have been identified. Further reducing the presence of Hg in the environment may help to alleviate the potential for adverse ecological health outcomes.

A review of the literature on effects of Hg on fish[188] reports results for numerous species including trout, bass (large and smallmouth), northern pike, carp, walleye, salmon, and others from laboratory and field studies. The studies were conducted in areas from New York to Washington and the effects studied are reproductive in nature. Although we cannot determine at this time whether these reproductive deficits are affecting fish populations across the U.S. it should be noted that it would seem reasonable that over time reproductive deficits would have an effect on populations. Lower fish populations would conceivably impact the ecosystem services like recreational fishing derived from having healthy aquatic ecosystems.

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[188] Crump, KL, and Trudeau, VL. Mercury-induced reproductive impairment in fish. Environmental Toxicology and Chemistry. Vol. 28, No. 5, 2009.

Mercury also affects avian species. In previous reports [189] much of the focus has been on large piscivorous species in particular the common loon. The loon is most visible to the public during the summer breeding season on northern lakes and they have become an important symbol of wilderness in these areas.[190] A multitude of loon watch, preservation, and protection groups have formed over the past few decades and have been instrumental in promoting conservation, education, monitoring, and research of breeding loons. [191] Significant adverse effects on breeding loons from Hg have been found to occur including behavioral (reduced nest-sitting), physiological (flight feather asymmetry) and reproductive (chicks fledged/territorial pair) effects and reduced survival.[192] Additionally, Evers, et al. (see footnote 5),

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[189] U.S. Environmental Protection Agency (EPA). 1997. Mercury Study Report to Congress. Volume V: Health Effects of Mercury and Mercury Compounds. EPA-452/R-97-007. U.S. EPA Office of Air Quality Planning and Standards, and Office of Research and Development; U.S. Environmental Protection Agency (U.S. EPA). 2005. *Regulatory Impact Analysis of the Final Clean Air Mercury Rule.* Office of Air Quality Planning and Standards, Research Triangle Park, NC., March; EPA report no. EPA-452/R-05-003. Available on the Internet at http://www.epa.gov/ttn/ecas/regdata/RIAs/mercury_ria_final.pdf.

[190] McIntyre, JW, Barr, JF. 1997. Common Loon (Gavia immer) in: Pool A, Gill F (eds) The Birds of North America. Academy of Natural Sciences, Philadelphia, PA, 313.

[191] McIntrye, JW, and Evers, DC, (eds) 2000. Loons: old history and new finding. Proceedings of a Symposium from the 1997 meeting, American Ornithologists' Union. North American Loon Fund, 15 August 1997, Holderness, NH, USA; Evers, DC, 2006. Status assessment and conservation plan for the common loon (Gavia immer) in North America. U.S. Fish and Wildlife Service, Hadley, MA, USA.

[192] Evers, DC, Savoy, LJ, DeSorbo, CR, Yates, DE, Hanson, W, Taylor, KM, Siegel, LS, Cooley, JH, Jr., Bank, MS, Major, A,

report that they believe that the weight of evidence indicates that population-level effects occur in parts of Maine and New Hampshire, and potentially in broad areas of the loon's range.

Recently attention has turned to other piscivorous species such as the white ibis, and great snowy egret. Although considered to be fish-eating generally, these wading birds have a very wide diet including crayfish, crabs, snails, insects and frogs. These species are experiencing a range of adverse effects due to exposure to Hg. The white ibis has been observed to have decreased foraging efficiency.[193] Additionally ibises have been shown to exhibit decreased reproductive success and altered pair behavior.[194] These effects include significantly more unproductive nests, male/male pairing, reduced courtship behavior and lower nestling production by exposed males. In this study, a worst-case scenario suggested by the results could involve up to a 50 percent reduction in fledglings due to MeHg in diet. In egrets, Hg has been implicated

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Munney, K, Mower, BF, Vogel, HS, Schoch, N, Pokras, M, Goodale, MW, Fair, J. Adverse effects from environmental mercury loads on breeding common loons. Ecotoxicology. 17:69-81, 2008; Mitro, MG, Evers, DC, Meyer, MW, and Piper, WH. Common loon survival rates and mercury in New England and Wisconsin. Journal of Wildlife Management. 72(3): 665-673, 2008.

[193] Adams, EM, and Frederick, PC. Effects of methylmercury and spatial complexity on foraging behavior and foraging efficiency in juvenile white ibises (Eudocimus albus). Environmental Toxicology and Chemistry. Vol 27, No. 8, 2008.

[194] Frederick, P, and Jayasena, N. Altered pairing behavior and reproductive success in white ibises exposed to environmentally relevant concentrations of methylmercury. Proceedings of The Royal Society B. doi: 10-1098, 2010.

in the decline of the species in south Florida[195] and Hoffman[196] has shown that egrets show liver and possibly kidney effects. Although ibises and egrets are most abundant in coastal areas and these studies were conducted in south Florida and Nevada the ranges of ibises and egrets extend to a large portion of the U.S.

Insectivorous birds have also been shown to suffer adverse effects due to Hg exposure. These songbirds such as Bicknell's thrush, tree swallows, and the great tit have shown reduced reproduction, survival, and changes in singing behavior. Exposed tree swallows produced fewer fledglings,[197] lower survival,[198] and had compromised immune competence.[199] The great tit has exhibited reduced singing behavior and smaller

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[195] Sepulveda, MS, Frederick, PC, Spalding, MG, and Williams, GE, Jr. Mercury contamination in free-ranging great egret nestlings (Ardea albus) from southern Florida, USA. Environmental Toxicology and Chemistry. Vol. 18, No. 5, 1999.

[196] Hoffman, DJ, Henny, CJ, Hill, EF, Grover, RA, Kaiser, JL, Stebbins, KR. Mercury and drought along the lower Carson River, Nevada: III. Effects on blood and organ biochemistry and histopathology of snowy egrets and black-crowned night-herons on Lahontan Reservoir, 2002-2006. Journal of Toxicology and Environmental Health, Part A. 72: 20, 1223-1241, 2009.

[197] Brasso, RL, and Cristol, DA. Effects of mercury exposure in the reproductive success of tree swallows (Tachycineta bicolor). Ecotoxicology. 17:133-141, 2008.

[198] Hallinger, KK, Cornell, KL, Brasso, RL, and Cristol, DA. Mercury exposure and survival in free-living tree swallows (Tachycineta bicolor). Ecotoxicology. Doi: 10.1007/s10646-010-0554-4, 2010.

[199] Hawley, DM, Hallinger, KK, Cristol, DA. Compromised immune competence in free-living tree swallows exposed to mercury. Ecotoxicology. 18:499-503, 2009.

song repertoire in areas of high contamination.[200] These effects may result in population reductions sufficient to affect people's enjoyment of these birds.

In mammals adverse effects have been observed in mink and river otter, both fish eating species. For otter from Maine and Vermont, maximum concentrations on Hg in fur nearly equal or exceed a concentration associated with mortality and concentration in liver for mink in Massachusetts/Connecticut and the levels in fur from mink in Maine exceed concentrations associated with acute mortality.[201] Adverse sublethal effects may be associated with lower Hg concentrations and consequently be more widespread than potential acute effects. These effects may include increased activity, poorer maze performance, abnormal startle reflex, and impaired escape and avoidance behavior.[202] Although we do not have data to show population level effects that would impact wildlife viewing and enjoyment these are ecosystem services potentially affected by impacts on these species.

The proposed rule will also reduce emissions of directly emitted PM and ozone precursors and estimates of the PM[2.5] -related co-benefits of these air quality improvements may be found in Table 28 of this

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[200] Gorissen, L, Snoeijs, T, Van Duyse, E, and Eens, M. Heavy metal pollution affects dawn singing behavior in a small passerine bird. Oecologia. 145: 540-509, 2005.

[201] Yates, DE, Mayack, DT, Munney, K, Evers DC, Major, A, Kaur, T, and Taylor, RJ. Mercury levels in mink (Mustela vison) and river otter (Lonra canadensis) from northeastern North America. Ecotoxicology. 14, 263-274, 2005.

[202] Scheuhammer, AM, Meyer MW, Sandheinrich, MB, and Murray, MW. Effects of environmental methylmercury on the health of wild birds, mammals, and fish. Ambio. Vol. 36, No. 1, 2007.

preamble. When characterizing uncertainty in the PM-mortality relationship, EPA has historically presented a sensitivity analysis applying alternate assumed thresholds in the PM concentration-response relationship. In its synthesis of the current state of the PM science, EPA's 2009 Integrated Science Assessment for Particulate Matter concluded that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship. In the RIA accompanying this rulemaking, rather than segmenting out impacts predicted to be associated levels above and below a "bright line" threshold, EPA includes a "lowest measured level" (LML) analysis that illustrates the increasing uncertainty that characterizes exposure attributed to levels of PM[2.5] below the LML of each epidemiological study used to estimate PM[2.5] -related premature death. Figures provided in the RIA show the distribution of baseline exposure to PM[2.5,] as well as the lowest air quality levels measured in each of the epidemiology cohort studies. This information provides a context for considering the likely portion of PM-related mortality benefits occurring above or below the LML of each study; in general, our confidence in the size of the estimated reduction PM[2.5] -related premature mortality diminishes as baseline concentrations of PM[2.5] are lowered. Using the Pope, *et al.* (2002) study, 86 percent of the population is exposed at or above the LML of 7.5 [mu]g/m<3>. Using the Laden, *et al.* (2006) study, 30 percent of the population is exposed at or above the LML of 10 [mu]g/m<3>. Although the LML analysis provides some insight into the level of uncertainty in the estimated PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of

modeled air quality concentrations. It is important to note that the monetized benefits include many but not all health effects associated with PM[2.5] exposure. Benefits are shown as a range from Pope, et al., (2002) to Laden, *et al.,* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type.

The cost analysis is also subject to uncertainties. Estimating the cost conversion from one process to another is more difficult than estimating the cost of adding control equipment because it is more dependent on plant specific information. More information on the cost uncertainties can be found in the RIA.

A summary of the monetized benefits and net benefits for the proposed rule at discount rates of 3 percent and 7 percent is in Table 28 of this preamble.

For more information on the benefits analysis, please refer to the RIA for this rulemaking, which is available in the docket.

B. Paperwork Reduction Act

The information collection requirements in this proposed rule will be submitted for approval to the OMB under the PRA, *44 U.S.C. 3501 et seq.* An ICR document has been prepared by EPA (ICR No. 2137.05).

The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all

operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (*42 U.S.C. 7414*). All information submitted to EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

This proposed rule would require maintenance inspections of the control devices but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $ 49.1 million. This includes 329,605 labor hours per year at a total labor cost of $ 27.0 million per year, and total non-labor capital costs of $ 22.1 million per year. This estimate includes initial and annual performance test, conducting and documenting a tune-up, semiannual excess emission reports, maintenance inspections, developing a monitoring plan, notifications, and recordkeeping. The total burden for the Federal government (averaged over the first 3 years after the effective date of the standard) is estimated to be 18,039 hours per year at a total labor cost of $ 877 million per year.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of

collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for our regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

To comment on EPA's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques, EPA has established a public docket for this proposed rule, which includes this ICR, under Docket ID number EPA-HQ-OAR-2009-0234. Submit any comments related to the ICR to EPA and OMB. *See* **ADDRESSES** section at the beginning of this preamble for where to submit comments to EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Office for EPA. Because OMB is required to make a decision concerning the ICR between 30 and 60 days after May 3, 2011, a comment to OMB is best assured of having its full effect if OMB receives it by June 2, 2011. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act (RFA), as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 et seq.

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's proposed rule on small entities, small entity is defined as (as defined by the Small Business Administration's (SBA) regulations at *13 CFR 121.201*): (1) A small business according to SBA size standards by the North American Industry Classification System category of the owning entity (for NAICS 221112 and 221122, the range of small business size standards for electric utilities is 4 million megawatt hours of production or less); (2) a small governmental jurisdiction that is a government of a city, county, town, township, village, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this proposed rule on small entities, EPA cannot certify that this action will not have a significant economic impact on a substantial number of small entities. This determination, which is included in the Initial Regulatory Flexibility Analysis (IRFA) found in Chapter 10 of the RIA for this proposed rule, is based

on the economic impact of this proposed rule to all affected small entities across the electric power sector.

The summary of the IRFA is as follows. EPA has assessed the potential impact of this action on small entities and found that approximately 102 of the estimated 1,400 EGUs potentially affected by today's proposed rule are owned by the 83 potentially affected small entities identified by EPA's analysis. EPA estimates that 59 of the 83 identified small entities will have annualized costs greater than 1 percent of their revenues.

Because the potential existed for a likely significant impact for substantial number of small entities, EPA convened a SBAR Panel to obtain advice and recommendation of representatives of the small entities that potentially would be subject to the requirements of this rule.

1. Panel Process and Panel Outreach

As required by RFA section 609(b), as amended by SBREFA, EPA has conducted outreach to small entities and on October 27, 2010, EPA's Small Business Advocacy Chairperson convened a Panel under RFA section 609(b). In addition to the Chair, the Panel consisted of the Director of the Sector Policies and Programs Division within EPA's Office of Air and Radiation, the Chief Counsel for Advocacy of SBA, and the Administrator of the Office of Information and Regulatory Affairs within OMB.

As part of the SBAR Panel process we conducted outreach with representatives from 18 various small entities that potentially would be affected by this rule. The SERs included representatives of EGUs owned by municipalities, cooperatives, and private investors. We distributed outreach materials to the SERs; these

materials included background and project history, CAA section 112 overview, constraints on the rulemaking, rulemaking options under consideration, and potential control technologies and estimated cost. We met with 14 of the SERs, as well as five non-SER participants from organizations representing power producers, on December 2, 2010, to discuss the outreach materials, potential requirements of the rule, and regulatory areas where EPA has discretion and could potentially provide flexibility. The Panel received written comments from, or on behalf of, 10 SERs following the meeting in response to discussions at the meeting and the questions posed to the SERs by the Agency. The SERs were specifically asked to provide comment on regulatory approaches that could help to minimize the rule's impact on small businesses.

2. Panel Recommendations for Small Business Flexibilities

Consistent with the RFA/SBREFA requirements, the Panel evaluated the assembled materials and small-entity comments on issues related to elements of the IRFA. A copy of the Final Panel Report (including all comments received from SERs in response to the Panel's outreach meeting) is included in the docket for this proposed rule. In general, the Panel recommended that EPA consider its various flexibilities to the maximum extent possible consistent with CAA requirements to mitigate the impacts of the rulemaking on small businesses and to seek comment on potential adverse economic impacts of the proposed rule on affected small entities and recommendations to mitigate such impacts. With respect to specific issues and options, however, there were varying recommendations from panel members. Issues and

options discussed among the panel members included: (1) MACT floor determinations and variability assessment; (2) monitoring, reporting, and recordkeeping requirements; (3) subcategorization; (4) area source standards; (5) work practice standards; (6) health based emission limits; (7) related Federal rules; (8) potential adverse economic impacts; and (9) concerns with the SBAR process. Panel member recommendations regarding each of these issues and options are presented in Chapter 9 of the Final Panel Report. As noted elsewhere in this preamble, this proposal is based on a regulatory alternative that includes subcategorization, MACT floor-based numerical emission limitations, work practice standards, alternative standards, alternative compliance options, and emissions averaging.

We invite comments on all aspects of the proposal and its impacts, including potential adverse impacts, on small entities.

D. Unfunded Mandates Reform Act of 1995

Title II of the UMRA of 1995, Public Law 104-4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. Under UMRA section 202, we generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to state, local, and tribal governments, in the aggregate, or to the private sector, of $ 100 million or more in any 1 year. Before promulgating a rule for which a written statement is needed, UMRA section 205 generally requires us to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves

the objectives of the rule. The provisions of UMRA section 205 do not apply when they are inconsistent with applicable law. Moreover, UMRA section 205 allows us to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before we establish any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, we must develop a small government agency plan under UMRA section 203. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We have determined that this proposed rule contains a Federal mandate that may result in expenditures of $ 100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Accordingly, we have prepared a written statement entitled "Unfunded Mandates Reform Act Analysis for the Proposed Toxics Rule" under UMRA section 202 that is within the RIA and which is summarized below.

1. Statutory Authority

As discussed elsewhere in this preamble, the statutory authority for this proposed rulemaking is CAA section 112. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. CAA section 112(b) lists the 188 chemicals, compounds, or groups of chemicals deemed by Congress to

be HAP. These toxic air pollutants are to be regulated by NESHAP.

CAA section 112(d) directs us to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT based standards. This NESHAP applies to all coal- and oil-fired EGUs.

In compliance with UMRA section 205(a), we identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives is presented in the RIA for this rulemaking and in the docket. The regulatory alternative upon which this proposed rule is based represents the MACT floor for all regulated pollutants for four of the five subcategories of EGUs and for all but one regulated pollutant for the fifth subcategory. These proposed MACT floor-based standards represent the least costly and least burdensome alternative. Beyond-the-floor emission limits for Hg are proposed for existing and new EGUs designed to burn coal having a calorific value less than 8,300 Btu/lb.

2. Social Costs and Benefits

The RIA prepared for this proposed rule including the Agency's assessment of costs and benefits and is in the docket.

It is estimated that 3 years after implementation of this proposed rule, HAP would be reduced by thousands of tons, including reductions in HCl, HF, metallic HAP (including Hg), and several other organic HAP from EGUs. Studies have determined a relationship between exposure to these HAP and the onset of cancer; however, the Agency is unable to provide a monetized estimate of the HAP benefits at

this time. In addition, there are significant reductions in PM[2.5] and in SO[2] that would occur, including approximately 84 thousand tons of PM[2.5] and over 2 million tons of SO[2]. These reductions occur by 2016 and are expected to continue throughout the life of the affected sources. The major health effect associated with reducing PM[2.5] and PM[2.5] precursors (such as SO[2]) is a reduction in premature mortality. Other health effects associated with PM[2.5] emission reductions include avoiding cases of chronic bronchitis, heart attacks, asthma attacks, and work-lost days *(i.e.*, days when employees are unable to work). Although we are unable to monetize the benefits associated with the HAP emissions reductions other than for Hg, we are able to monetize the benefits associated with the PM[2.5] and SO[2] emissions reductions. For SO[2] and PM[2.5], we estimated the benefits associated with health effects of PM but were unable to quantify all categories of benefits (particularly those associated with ecosystem and visibility effects). Our estimates of the monetized benefits in 2016 associated with the implementation of the proposed alternative range from $ 59 billion (2007 dollars) to $ 140 billion (2007 dollars) when using a 3 percent discount rate (or from $ 53 billion (2007 dollars) to $ 130 billion (2007 dollars) when using a 7 percent discount rate). Our estimate of social costs is $ 10.9 billion (2007 dollars). For more detailed information on the benefits and costs estimated for this proposed rulemaking, refer to the RIA in the docket.

3. Future and Disproportionate Costs

UMRA requires that we estimate, where accurate estimation is reasonably feasible, future compliance costs imposed by this proposed rule and any disproportionate budgetary effects. Our estimates of the

future compliance costs of this proposed rule are discussed previously in this preamble.

EPA assessed the economic and financial impacts of the rule on government-owned entities using the ratio of compliance costs to the value of revenues from electricity generation, and our results focus on those entities for which this measure could be greater than 1 percent or 3 percent of base revenues. EPA projects that 55 government entities will have compliance costs greater than 1 percent of base generation revenue in 2016, and 37 may experience compliance costs greater than 3 percent of base revenues. Also, one government entity is estimated to have all of its affected units retire. Overall, 17 units owned by government entities retire. It is also worth noting that two-thirds of the net compliance costs shown above are due to lost profits from retirements. More than half of those lost profits arise from retiring two large units, according to EPA modeling. For more details on these results and the methodology behind their estimation, see the results included in the RIA and which are discussed previously in this preamble.

4. Effects on the National Economy

UMRA requires that we estimate the effect of this proposed rule on the national economy. To the extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of the U.S. goods and services, if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material.

The nationwide economic impact of this proposed rule is presented in the RIA in the docket. This analysis provides estimates of the effect of this

proposed rule on some of the categories mentioned above. The results of the economic impact analysis are summarized previously in this preamble. The results show that there will be a less than 4 percent increase in electricity price on average nationwide in 2016, and a less than 7 percent increase in natural gas price nationwide in 2016. Power generation from coal-fired plants will fall by about 1 percent nationwide in 2016.

5. Consultation With Government

UMRA requires that we describe the extent of the Agency's prior consultation with affected State, local, and tribal officials, summarize the officials' comments or concerns, and summarize our response to those comments or concerns. In addition, UMRA section 203 requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a proposal. Consistent with the intergovernmental consultation provisions of UMRA section 204, EPA has initiated consultations with governmental entities affected by this proposed rule. EPA invited the following 10 national organizations representing state and local elected officials to a meeting held on October 27, 2010, in Washington DC: (1) National Governors Association, (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations of elected state and local officials have been identified by EPA as the "Big 10" organizations appropriate to contact for purpose of consultation with elected officials. The purposes of the consultation were

to provide general background on the proposal, answer questions, and solicit input from State/local governments. During the meeting, officials asked clarifying questions regarding CAA section 112 requirements and central decision points presented by EPA (*e.g.*, use of surrogate pollutants to address HAP, subcategorization of source category, assessment of emissions variability). They also expressed uncertainty with regard to how utility boilers owned/operated by state and local entities would be impacted, as well as with regard to the potential burden associated with implementing the rule on state and local entities (*i.e.*, burden to re-permit affected EGUs or update existing permits). Officials requested, and EPA provided, addresses associated with the 112 state and local governments estimated to be potentially impacted by the proposed rule. EPA has not received additional questions or requests from state or local officials.

Consistent with UMRA section 205, EPA has identified and considered a reasonable number of regulatory alternatives. Because the potential existed for a likely significant impact for substantial number of small entities, EPA convened a SBAR Panel to obtain advice and recommendation of representatives of the small entities that potentially would be subject to the requirements of the rule. As part of that process, EPA considered several options. Those options included establishing emission limits, establishing work practice standards, establishing subcategories, and consideration of monitoring options. The regulatory alternative selected is a combination of the options considered and includes proposed provisions regarding a number of the recommendations resulting from the SBAR Panel process as described below (see elsewhere in this preamble for more detail).

EPA determined that there is a distinguishable difference in emissions characteristics associated with five EGU design types and that these characteristics may affect the feasibility and/or effectiveness of emission control. Thus, the five types of units are proposed to be regulated separately (*i.e.*, subcategorized) to account for the difference in emissions and applicable controls. The proposal establishes three subcategories for coal-fired EGUs and two subcategories for oil-fired EGUs: (1) Coal-fired units designed to burn coal having a calorific value of 8,300 Btu/lb or greater, (2) coal-fired units designed to burn virgin coal having a calorific value less than 8,300 Btu/lb, (3) IGCC units (for Hg emissions only), (4) liquid oil units, and (5) solid oil-derived units.

The regulatory alternative upon which the proposed standards for coal-fired EGUs are based includes: (1) MACT floor-based numerical emission limitations for HCl (a HAP as well as a surrogate for all other acid gas HAP) and for PM (a surrogate for non-Hg metallic HAP) for existing and new EGUs in all three subcategories; (2) MACT floor-based numerical emission limitations for Hg for existing and new coal-fired units designed to burn coal having a calorific value of 8,300 Btu/lb or greater and IGCC units; (3) beyond-the-floor numerical emission limitations for Hg for existing and new coal-fired units designed to burn virgin coal having a calorific value less than 8,300 Btu/lb; and (4) work practices to limit emissions of dioxin/furan organic HAP and non-dioxin/furan organic HAP for existing and new EGUs in all three subcategories. The regulatory alternative upon which the proposed standards for oil-fired EGUs are based includes: (1) MACT floor-based numerical emission limitations for Hg, total non-Hg metallic HAP, HCl, and HF for existing and new EGUs in both subcategories; and (2)

work practices to limit emissions of dioxin/furan organic HAP and non-dioxin/furan organic HAP for existing and new EGUs in both subcategories. The proposed use of surrogate pollutants would result in reduced compliance costs because testing would only be required for the surrogate pollutants (*i.e.*, HCl and PM) versus for the HAP (*i.e.*, acid gases and non-Hg metals).

EPA also is proposing three alternative standards for certain subcategories: (1) SO[2] (as an alternate to HCl for all subcategories with add-on FGD systems except IGCC units and liquid oil-fired units); (2) individual non-Hg metallic HAP (as an alternate to PM for all subcategories except liquid oil-fired units, and as an alternative to total non-Hg metallic HAP for the liquid oil-fired units subcategory); and (3) total non-Hg metallic HAP (as an alternate to PM for all subcategories except liquid oil-fired units). In addition, liquid oil-fired EGUs may choose to demonstrate compliance with the Hg, non-Hg metallic HAP, HCl, and HF emission limits on the basis of fuel analysis. Maximum fuel inlet values for Hg, non-Hg metals, chlorine, and fluorine would be established based on the inlet fuel values measured during the performance test indicating compliance with the emission limits. We also are proposing that owners and operators of existing affected sources may demonstrate compliance by emissions averaging for units at the affected source that are within a single subcategory. Alternative standards, alternative compliance options, and emissions averaging can provide sources the flexibility to comply in the least costly manner.

The proposed work practice standard, which requires implementation of an annual performance (compliance) test program includes requirements to

inspect the burner, flame pattern, and the system controlling the air-to-fuel ratio, and make any necessary adjustments and/or conduct any required maintenance and repairs; minimize CO emissions consistent with the manufacturer's specifications; measure the concentration of CO in the effluent stream before and after any adjustments are made; and submit an annual report containing the concentrations of CO and O[2] measured before and after adjustments, a description of any corrective actions taken as a part of the combustion adjustment, and the type and amount of fuel used over the 12 months prior to the annual adjustment.

E. Executive Order 13132, Federalism

Under EO 13132, EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by state and local governments, or EPA consults with state and local officials early in the process of developing the proposed action.

EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on state or local governments, and the Federal government will not provide the funds necessary to pay those costs. Accordingly, EPA provides the following federalism summary impact statement as required by section 6(b) of EO 13132.

Based on the estimates in EPA's RIA for today's proposed rule, the proposed regulatory option, if promulgated, may have federalism implications because the option may impose approximately $ 666.3

million in annual direct compliance costs on an estimated 97 state or local governments. Specifically, we estimate that there are 81 municipalities, 5 states, and 11 political subdivisions (*i.e.*, a public district with territorial boundaries embracing an area wider than a single municipality and frequently covering more than one county for the purpose of generating, transmitting and distributing electric energy) that may be directly impacted by today's proposed rule. Responses to EPA's 2010 ICR were used to estimate the nationwide number of potentially impacted state or local governments. As previously explained, this 2010 survey was submitted to all coal- and oil-fired EGUs listed in the 2007 version of DOE/EIA's "Annual Electric Generator Report," and "Power Plant Operations Report."

EPA consulted with state and local officials in the process of developing the proposed rule to permit them to have meaningful and timely input into its development. EPA met with 10 national organizations representing state and local elected officials to provide general background on the proposal, answer questions, and solicit input from *state /*local governments. The UMRA discussion in this preamble includes a description of the consultation.

In the spirit of EO 13132, and consistent with EPA policy to promote communications between EPA and state and local governments, EPA specifically solicits comment on this proposed action from state and local officials.

F. Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

Subject to EO 13175 *(65 FR 67249,* November 9, 2000) EPA may not issue a regulation that has tribal

implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement. Executive Order 13175 requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications."

EPA has concluded that this action may have tribal implications. However, it will neither impose substantial direct compliance costs on tribal governments, nor preempt tribal law. This proposed rule would impose requirements on owners and operators of EGUs. EPA is aware of three coal-fired EGUs located in Indian Country but is not aware of any EGUs owned or operated by tribal entities.

EPA offered consultation with tribal officials early in the process of developing this proposed regulation to permit them to have meaningful and timely input into its development. Consultation letters were sent to 584 tribal leaders. The letters provided information regarding EPA's development of NESHAP for EGUs and offered consultation. Three consultation meetings were held on December 7, 2010, with the Upper Sioux Community of Minnesota; on December 13 with Moapa Band of Paiutes, Forest County Potawatomi, Standing Rock Sioux Tribal Council, Fond du Lac Band of Chippewa; and on January 5, 2011 with the Forest County Potawatomi, and a representative from the National Tribal Air Association (NTAA). In these meetings, EPA presented the authority under the CAA used to develop these rules, and an overview of the

industry and the industrial processes that have the potential for regulation. Tribes expressed concerns about the impact of EGUs on the reservations. Particularly, they were concerned about potential Hg deposition and the impact on the water resources of the Tribes, with particular concern about the impact on subsistence lifestyles for fishing communities, the cultural impact of impaired water quality for ceremonial purposes, and the economic impact on tourism. In light of these concerns, the tribes expressed interest in an expedited implementation of the rule, they expressed concerns about how the Agency would consider variability in setting the standards and use tribal-specific fish consumption data from the tribes in our assessments, they were not supportive of using work practice standards as part of the rule, and they asked the Agency to consider going beyond-the-floor to offer more protection for the tribal communities. A more specific list of comments can be found in the Docket.

In addition to these consultations, EPA also conducted outreach on this rule through presentations at the National Tribal Forum in Milwaukee, WI, and on NTAA calls. EPA specifically requested tribal data that could support the appropriate and necessary analysis and the RIA for this rule. We will also hold additional meetings with tribal environmental staff to inform them of the content of this proposal as well as provide additional consultation with tribal elected officials where it is appropriate.

EPA specifically solicits additional comment on this proposed rule from tribal officials.

G. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045 *(62 FR 19,885,* April 23, 1997) applies to any rule that: (1) Is determined to be "economically significant" as defined under EO 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of this planned rule on children, and explain why this planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This proposed rule is subject to EO 13045 because it is an economically significant regulatory action as defined by EO 12866, and we believe that the action concerns an environmental health risk which may have a disproportionate impact on children. Although this proposed rule is based on technology performance, the statute is designed to require standards that are likely to protect against hazards to public health with an adequate margin of safety as described elsewhere in this document. The protection offered by this proposed rule is especially important for children, especially the developing fetus. As referenced in the section entitled, "Consideration of Health Risks to Children and Environmental Justice Communities" children are more vulnerable than adults to many HAP emitted by EGUs due to differential behavior patterns and physiology. These unique susceptibilities were carefully considered in a number of different ways in the analyses associated with this rulemaking, and are summarized elsewhere in this document.

The public is invited to submit comments or identify peer-reviewed studies and data that assess effects of early life exposure to this proposed rule.

H. Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211, *(66 FR 28355,* May 22, 2001), provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as significant energy actions. Section 4(b) of EO 13211 defines "significant energy actions" as "any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) That is a significant regulatory action under EO 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action." This proposed rule is a "significant regulatory action" because it may likely have a significant adverse effect on the supply, distribution, or use of energy. The basis for the determination is as follows.

We estimate a less than 4 percent price increase for electricity nationwide in 2016 and a 1 percent percentage fall in coal-fired power production. EPA projects that delivered natural gas prices will increase by about 1 percent over the 2015 to 2030 timeframe. For more information on the estimated energy effects, please refer to the economic impact analysis for this proposed rule. The analysis is available in the RIA, which is in the public docket.

Therefore, we conclude that this proposed rule when implemented is likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104-113; *15 U.S.C. 272* note) directs EPA to use voluntary consensus standards (VCS) in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

This rulemaking involves technical standards. EPA cites the following standards in this proposed rule: EPA Methods 1, 2, 2F, 2G, 3A, 3B, 4, 5, 5D, 6, 6C, 9, 19, 26, 26A, 29, 30A, 30B, and 202 of 40 CFR part 60. Consistent with the NTTAA, EPA conducted searches to identify VCS in addition to these EPA methods. No applicable voluntary standards were identified for EPA Methods 2F, 2G, 8, 19, 201A, and 202. The search and review results have been documented and are placed in the docket for this proposed rule.

EPA has decided to use American National Standards Institute (ANSI)/ASME PTC 19-10-1981 Part 10, "Flue and Exhaust Gas Analyses," acceptable as an alternative to Methods 3B (for CO[2], CO, and O[2]), 6 (for SO[2]), 6A and 6B (for CO[2] and SO[2]).

This standard is available from the ASME, Three Park Avenue, New York, NY 10016-5990.

Another VCS, ASTM D6735-01, "Standard Test Method for Measurement of Gaseous Chlorides and Fluorides from Mineral Calcining Exhaust Sources Impinger Method," is an acceptable alternative to EPA Methods 26 and 26A.

An additional VCS, ASTM D6784-02 (2008)—Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method) is acceptable as an alternative to Method 29 for Hg, but only if the standard falls within the applicable concentration range of 0.5 to 100 [mu]g/Nm<3>.

During the search, if the title or abstract (if provided) of the VCS described technical sampling and analytical procedures that are similar to EPA's reference method, EPA ordered a copy of the standard and reviewed it as a potential equivalent method. All potential standards were reviewed to determine the practicality of the VCS for this rule. This review requires significant method validation data which meets the requirements of EPA Method 301 for accepting alternative methods or scientific, engineering and policy equivalence to procedures in EPA reference methods. EPA may reconsider determinations of impracticality when additional information is available for particular VCS.

The search identified 22 other VCS that were potentially applicable for this rule in lieu of EPA reference methods. After reviewing the available standards, EPA determined that 22 candidate VCS (ASTM D3154-00 (2006), ASME B133.9-1994 (2001),

ANSI/ASME PTC 19-10-1981 Part 10, ASTM D5835-95 (2007), International Organization for Standards (ISO) 10396:1993 (2007), ISO 12039:2001, ASTM D6522-00 (2005), Canadian Standards Association (CAN/CSA) Z223.2-M86 (1999), ISO 9096:1992 (2003), ANSI/ASME PTC-38-1980 (1985), ASTM D3685/D3685M-98 (2005), ISO 7934:1998, ISO 11632:1998, ASTM D3464-96 (2007), ASTM D3796-90 (2004), ISO 10780:1994, CAN/CSA Z223.21-M1978, ASTM D3162-94 (2005), CAN/CSA Z223.1-M1977, EN 1911-1,2,3 (1998), EN 13211:2001, CAN/CSA Z223.26-M1987) identified for measuring emissions of pollutants or their surrogates subject to emission standards in the proposed rule would not be practical due to lack of equivalency, documentation, validation data, and other important technical and policy considerations. These 22 methods are listed Attachment 1 to the documentation memo, along with the EPA review comments, which may be found in the docket.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 *(59 FR 7629,* February 16, 1994) establishes Federal executive policy on EJ. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations, low-income, and tribal populations in the U.S.

This proposed rule establishes national emission standards for new and existing EGUs that combust

coal and oil. EPA estimates that there are approximately 1,400 units located at 550 facilities covered by this proposed rule.

This proposed rule will reduce emissions of all the listed HAP that come from EGUs. This includes metals (Hg, As, Be, Cd, Cr, Pb, Mn, Ni, and Se), organics (POM, acetaldehyde, acrolein, benzene, dioxins, ethylene dichloride, formaldehyde, and PCB), and acid gases (HCl and HF). At sufficient levels of exposure, these pollutants can cause a range of health effects including cancer; irritation of the lungs, skin, and mucous membranes; effects on the central nervous system such as memory and IQ loss and learning disabilities; damage to the kidneys; and other acute health disorders.

The proposed rule will also result in substantial reductions of criteria pollutants such as CO, PM, and SO[2]. Sulfur dioxide is a precursor pollutant that is often transformed into fine PM (PM[2.5]) in the atmosphere; some of the directly-emitted PM is in the form of PM[2.5]. Reducing emissions of PM and SO[2] will, as a result, reduce concentrations of PM[2.5] in the atmosphere. These reductions in PM[2.5] will provide large health benefits, such as reducing the risk of premature mortality for adults, chronic and acute bronchitis, childhood asthma attacks, and other respiratory and cardiovascular diseases. (For more details on the health effects of metals, organics, and PM[2.5], please refer to the RIA contained in the docket for this rulemaking.) This proposed rule will also have a small effect on electricity and natural gas prices and has the potential to affect the cost structure of the utility industry and could lead to shifts in how and where electricity is generated. Although energy prices are estimated to increase, we can only estimate

national impacts. We are unable to determine impacts other than at the national level at this time.

Pursuant to EO 12898 and the "Interim Guidance on Considering Environmental Justice During the Development of an Action" (July 2010), during development of a rule EPA considers whether there are positive or negative impacts of the action that appear to affect low-income, minority, or tribal communities disproportionately. Regardless of whether a disproportionate effect exists, EPA also considers whether there is a chance for these communities to meaningfully participate in the rulemaking process.

Today's proposed rule is one of a group of regulatory actions that EPA will take over the next several years to respond to statutory and judicial mandates that will reduce exposure to HAP and PM[2.5], as well as to other pollutants, from EGUs and other sources. In addition, EPA will pursue energy efficiency improvements throughout the economy, along with other Federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements. Together, these rules and actions will have substantial and long-term effects on both the U.S. power industry and on communities currently breathing dirty air. Therefore, we anticipate significant interest in many, if not most, of these actions from EJ communities, among many others.

1. Key EJ Aspects of the Rule

This is an air toxics rule; therefore, it does not permit emissions trading among sources. Instead, this proposed rule will place a limit on the rates of Hg and other HAP emitted from each affected EGU. As a result, emissions of Hg and other HAP such as HCl

will be substantially reduced in the vast majority of states. In some states, however, there may be small increases in Hg emissions due to shifts in electricity generation from EGUs with higher emission rates to EGUs with already low emission rates. Hydrogen chloride emissions are projected to increase at a small number of sources but that does not lead to any increased emissions at the state level.

The primary risk analysis to support the finding that this proposed rule is both appropriate and necessary includes an analysis of the effects of Hg from EGUs on people who rely on freshwater fish they catch as a regular and frequent part of their diet. These groups are characterized as subsistence level fishing populations or fishers. A significant portion of the data in this analysis came from published studies of EJ communities where people frequently consume locally-caught freshwater fish. These communities included: (1) White and black populations (including female and poor strata) surveyed in South Carolina; (2) Hispanic, Vietnamese and Laotian populations surveyed in California; and (3) Great Lakes tribal populations (Chippewa and Ojibwe) active on ceded territories around the Great Lakes. These data were used to help estimate risks to similar populations beyond the areas where the study data was collected. For example, while the Vietnamese and Laotian survey data were collected in California, given the ethnic (heritage) nature of these high fish consumption rates, we assumed that they could also be associated with members of these ethnic groups living elsewhere in the U.S. Therefore, the high-end consumption rates referenced in the California study for these ethnic groups were used to model risk at watersheds elsewhere in the U.S. As a result of this approach, the specific fish consumption patterns of several different

EJ groups are fundamental to EPA's assessment of both the underlying risks that make this proposed rule appropriate and necessary, and of the analysis of the benefits of reducing exposure to Hg and the other hazardous air pollutants.

EPA's full analysis of risks from consumption of Hg-contaminated fish are contained in the preamble for this rule. The effects of this proposed rule on the health risks from Hg and other HAP are presented in the preamble and in the RIA for this rule. This information can be accessed through docket EPA-HQ-OAR-2009-0234 and from the main EPA webpage for the rule http://www.epa.gov/ttn/atw/utility/utilitypg.html.

2. Potential Environmental and Public Health Impacts to Vulnerable Populations

EPA has conducted several analyses that provide additional insight on the potential effects of this rule on EJ communities. These include: (1) The socio-economic distribution of people living close to affected EGUs who may be exposed to pollution from these sources; and (2) an analysis of the distribution of health effects expected from the reductions in PM[2.5] that will result from implementation of this proposed rule (so-called "co-benefits").

a. Socio-Economic Distribution. As part of the analysis for this proposed rule, EPA reviewed the aggregate demographic makeup of the communities near EGUs covered by this proposed rule. Although this analysis gives some indication of populations that may be exposed to levels of pollution that cause concern, it does NOT identify the demographic characteristics of the most highly affected individuals or communities. EGUs usually have very tall emission

stacks; this tends to disperse the pollutants emitted from these stacks fairly far from the source. In addition, several of the pollutants emitted by these sources, such as Hg and SO[2], are known to travel long distances and harm both the environment and human health hundreds or even thousands of miles from where they were emitted.

This proximity-to-the-source review is included in the analysis for this proposed rule because some EGUs emit enough Ni or Cr to cause elevated lifetime cancer risks greater than 1 in a million in nearby communities. In addition, EPA's analysis indicates that there are localized areas with elevated levels of Hg deposition around most U.S. EGUs.

The review identified those census blocks within two circular distances (5 km and 50 km) of coal-fired EGUs and determined their demographic and socio-economic composition (*e.g.*, race, income, education, etc.). The radius of 5 km (or approximately 3 miles) was chosen because it has been used in other demographic analyses focused on areas around potential sources. The radius of 50 km (or approximately 31 miles) was used to approximate the distance from the source where elevated levels of Hg deposition might occur and may also be indicative of the area where risks from non-Hg HAP are most likely to occur.

The results of EPA's demographic analysis for coal fired EGUs are shown in the following table:

Table 30—Comparative Summary of the Demographics Within 5 KM (3 Miles) and 50 KM (31 Miles) of the Affected Sources

	White (%)	African American (%)	Native American (%)	Other and multi-racial (%)	Hispanic (%)	Minority (%)	Below poverty line (%)
5 km (3-mile) Buffer	70.8	15.8	0.7	12.7	15.5	35.5	15.6
50 km (31.1 miles) Buffer	74.5	15.2	0.5	9.7	9.9	29.7	11.6
National Average	75.1	12.3	0.9	11.7	13.7	31.6	13.1

The data indicate that coal-fired EGUs are located in areas where minority share of the population living within a 3-mile buffer is higher than the national average. For these same areas, the percent of the population below the poverty line is also higher than the national average. At 50 km from the source, however, the demographics are different. Although the percent African American remain above the national average, the percent of minority (including Native Americans) and the percent of the population living below the poverty line decrease below their respective national averages. These results are presented in more detail in the "Review of Proximity Analysis,"

February 2011, a copy of which is available in the docket.

b. PM[2.5] (Co-Benefits) Analysis. As mentioned above, many of the steps EGUs take to reduce their emissions of air toxics as required by this proposed rule will also reduce emissions of PM and SO[2]. As a result, this proposed rule will reduce concentrations of PM[2.5] in the atmosphere. Exposure to PM[2.5] can cause or contribute to adverse health effects, such as asthma and heart disease, that significantly affect many minority, low-income, and tribal individuals and their communities. Fine PM (PM[2.5]) is particularly (but not exclusively) harmful to children, the elderly, and people with existing heart and lung diseases, including asthma. Exposure can cause premature death and trigger heart attacks, asthma attacks in children and adults with asthma, chronic and acute bronchitis, and emergency room visits and hospitalizations, as well as milder illnesses that keep children home from school and adults home from work. Missing work due to illness or the illness of a child is a particular problem for people who work jobs that do not provide paid sick days. Many low-wage employees also risk losing their jobs if they are absent too often, even if it is due to their own illness or the illness of a child or other relative. Finally, many individuals in these communities also lack access to high quality health care to treat these types of illnesses. Due to all these factors, many minority and low-income communities are particularly susceptible to the health effects of PM[2.5] and receive many benefits from reducing it.

We estimate that in 2016 the PM-related annual benefits of the proposed rule for adults include approximately 6600 to 17,000 fewer premature mortalities,

4,300 fewer cases of chronic bronchitis, 10,000 fewer non-fatal heart attacks, 12,000 fewer hospitalizations (for respiratory and cardiovascular disease combined), 4.9 million fewer days of restricted activity due to respiratory illness and approximately 830,000 fewer lost work days. We also estimate substantial health improvements for children in the form of 110,000 fewer asthma attacks, 6,700 fewer hospital admissions due to asthma, 10,000 fewer cases of acute bronchitis, and approximately 210,000 fewer cases of upper and lower respiratory illness.

We also examined the PM[2.5] mortality risks according to race, income, and educational attainment. We then estimated the change in PM[2.5] mortality risk as a result of this proposed rule among people living in the counties with the highest (top 5 percent) PM[2.5] mortality risk in 2005. We then compared the change in risk among the people living in these "high-risk" counties with people living in all other counties.

In 2005, people living in the highest-risk counties and in the poorest counties have substantially higher risks of PM[2.5] -related death than people living in the other 95 percent of counties. This was true regardless of race; the difference between the groups of counties for each race is large while the differences among races in both groups of counties is very small. In contrast, the analysis found that people with less than high school education have significantly greater risks from PM[2.5] mortality than people with a greater than high school education. This was true both for the highest-risk counties and for the other counties. In summary, the analysis indicates that in 2005, educational status, living in one of the poorest

counties, and living in a high-risk county are associated with higher PM[2.5] mortality risk while race is not.

Our analysis finds that this proposed rule will significantly reduce the PM[2.5] mortality among all populations of different races living throughout the U.S. compared to both 2005 and 2016 pre-rule (i.e., base case) levels. The analysis indicates that people living in counties with the highest rates (top 5 percent) of PM[2.5] mortality risk in 2005 receive the largest reduction in mortality risk after this rule takes effect. We also find that people living in the poorest 5 percent of the counties receive a larger reduction in PM[2.5] mortality risk than all other counties. More information can be found in Appendix C of the RIA.

EPA estimates that the benefits of the proposed rule are distributed among these populations fairly evenly. Therefore, there is no indication that people of particular race, income, or level of education receive a greater benefit (or smaller benefit) than others. However, the analysis does indicate that this proposed rule in conjunction with the implementation of existing or proposed rules (*e.g.*, the Transport Rule) will reduce the disparity in risk between those in the highest-risk counties and the other 95 percent of counties for all races and educational levels. In addition, in many cases implementation of this proposed rule and other rules will, together, reduce risks in the highest-risk counties to the approximate level of risk for the rest on the counties before implementation.

These results are presented in more detail in the "Benefits Appendix" to this rule, a copy of which is available in the docket.

3. Meaningful Public Participation

EPA defines "Environmental Justice" to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and polices. To promote meaningful involvement, EPA has developed a communication and outreach strategy to ensure that interested communities have access to this proposed rule, are aware of its content, and have an opportunity to comment during the comment period. During the comment period, EPA will publicize the rulemaking via newsletters, EJ listserves, webinars and the internet, including the Office of Policy's (OP) Rulemaking Gateway Web site (http://yosemite.epa.gov/opei/RuleGate.nsf/). EPA will also provide general rulemaking fact sheets (*e.g.*, why is this important for my community) for EJ community groups and conduct conference calls with interested communities.

Once this rule is finalized and implemented, affected EGUs will need to update their operating (Title V) permits to reflect their new emissions limits and any other applicable requirements (*i.e.*, monitoring and recordkeeping) from this rule. The Title V permitting process provides that most permit actions must include an opportunity for public review and comments. In addition, after the public review process, EPA has an opportunity to review the proposed permit and object to its issuance if it does not meet CAA requirements. This process gives members of affected communities the opportunity to comment on the permit conditions for specific sources affected by this rulemaking.

4. Summary

This proposed rule strictly limits the emissions rate of Hg and other HAP from every affected EGU in the U.S. EPA's analysis indicates substantial health benefits, including for vulnerable populations, from reductions in PM[2.5]. EPA's analysis also indicates reductions in risks for individuals, including for members of many minority populations, who eat fish frequently from U.S. lakes and rivers and who live near affected sources. Based on all the available information, EPA has determined that this proposed rule will not have disproportionately high and adverse human health or environmental effects on minority, low-income, or tribal populations. EPA is providing multiple opportunities for EJ communities to both learn about and comment on this rule and welcomes their participation.

List of Subjects in 40 CFR Parts 60 and 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: March 16, 2011.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of the Federal Regulations is proposed to be amended as follows:

PART 60—[AMENDED]

1. The authority citation for part 60 continues to read as follows:

Authority: *42 U.S.C. 7401, et seq.*

Subpart A—[Amended]

2. Section 60.17 is amended:

a. By redesignating paragraphs (a)(91) and (a)(92) as paragraphs (a)(94) and (a)(95);

b. By redesignating paragraphs (a)(89) and (a)(90) as paragraphs (a)(91) and (a)(92);

c. By redesignating paragraphs (a)(54) through (a)(88) as paragraphs (a)(55) through (a)(89);

d. By adding paragraph (a)(54);

e. By adding paragraph (a)(90); and

f. By adding paragraph (a)(93) to read as follows:

§ 60.17 Incorporations by Reference.

* * * * *

(54) ASTM D3699—08, Standard Specification for Kerosine, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

(90) ASTM D6751-11, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

(94) ASTM D7467-10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

Subpart D—[Amended]

3. The heading to Subpart D is revised to read as follows:

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators

4. Section 60.40 is amended by revising paragraph (e) to read as follows:

§ 60.40 Applicability and designation of affected facility.

* * * * *

(e) Any facility covered under either subpart Da or KKKK is not covered under this subpart.

5. Section 60.41 is amended by adding the definitions of "natural gas" to read as follows:

§ 60.41 Definitions.

* * * * *

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard

cubic meter (910 and 1,150 Btu per dry standard cubic foot).

* * * * *

6. Section 60.42 is amended as follows:

a. By revising paragraph (a) introductory text.

b. By adding paragraph (d).

c. By adding paragraph (e).

§ 60.42 Standard for Particulate Matter (PM).

(a) Except as provided under paragraphs (b), (c), (d), and (e) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:

* * * * *

(d) An owner and operator of an affected facility that combusts only natural gas and that is subject to a federally enforceable permit limiting fuel use to natural gas is exempt from the PM and opacity standards specified in paragraph a of this section.

(e) An owner or operator of an affected facility that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO[2] emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO[2] or PM is exempt from the PM standards specified in paragraph a of this section.

7. Section 60.45 is amended as follows:

a. By revising paragraph (a).

b. By revising paragraphs (b) introductory text and (b)(1) through (b)(5).

c. By revising paragraph (b)(6) introductory text.

§ 60.45 Emissions and Fuel Monitoring.

(a) Each owner or operator of an affected facility subject to the applicable emissions standard shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a continuous emissions monitoring system (CEMS) for measuring SO[2] emissions, NO[X] emissions, and either oxygen (O[2]) or carbon dioxide (CO[2]) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS and COMS requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil-fuel-fired steam generator that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO[2] emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO[2] or PM, COMS for measuring the opacity of emissions and CEMS for measuring SO[2] emissions are not required if the owner or operator monitors SO[2] emissions by fuel sampling and analysis or fuel receipts.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring SO[2] emissions is not required if the owner or operator monitors SO[2] emissions by fuel sampling and analysis.

(3) Notwithstanding § 60.13(b), installation of a CEMS for NO[X] may be delayed until after the initial

performance tests under § 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of NO[X] are less than 70 percent of the applicable standards in § 60.44, a CEMS for measuring NO[X] emissions is not required. If the initial performance test results show that NO[X] emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for NO[X] within one year after the date of the initial performance tests under § 60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator is not required to and elects not to install any CEMS for SO[2] and NO[X], a CEMS for measuring either O[2] or CO[2] is not required.

(5) For affected facilities using a PM CEMS, a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section § 60.48Da of this part, or an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part a COMS is not required.

(6) A COMS for measuring the opacity of emissions is not required for an affected facility that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO[2], or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to

comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

* * * * *

Subpart Da—[Amended]

8. The heading to Subpart Da is revised to read as follows:

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units

9. Section 60.40Da is amended by revising paragraph (e) and by adding paragraph (f) to read as follows:

§ 60.40Da Applicability and designation of affected facility.

* * * * *

(e) Applicability of the requirement of this subpart to an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit is as specified in paragraphs (e)(1) through (e)(3) of this section.

(1) Affected facilities (i.e. heat recovery steam generators used with duct burners) associated with a stationary combustion turbine that are capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel are subject to this subpart except in cases when the affected facility (i.e. heat recovery steam generator) meets the applicability requirements and is subject to subpart KKKK of this part.

(2) For heat recovery steam generators used with duct burners subject to this subpart, only emissions resulting from the combustion of fuels in the steam generating unit (i.e. duct burners) are subject to the

standards under this subpart. (The emissions resulting from the combustion of fuels in the stationary combustion turbine engine are subject to subpart GG or KKKK, as applicable, of this part).

(3) Any affected facility that meets the applicability requirements and is subject to subpart Eb or subpart CCCC of this part is not subject to the emission standards under subpart Da.

(f) *General Duty to minimize emissions.* At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

10. Section 60.41Da is amended by revising the definitions of "gaseous fuel," "integrated gasification combined cycle electric utility steam generating unit," "petroleum" and "steam generating unit," adding the definitions of "affirmative defense" and "petroleum coke," and deleting the definitions of "dry flue gas desulfurization technology," "emission rate period," and "responsible official" to read as follows:

§ 61.41Da Definitions.

* * * * *

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put

forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

* * * * *

Gaseous fuel means any fuel that is present as a gas at standard conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

* * * * *

Integrated gasification combined cycle electric utility steam generating unit or *IGCC electric utility steam generating unit* means an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction or repair. No solid fuel is directly burned in the unit during operation.

* * * * *

Petroleum for facilities constructed, reconstructed, or modified before May 4, 2011, means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, and residual oil. For units constructed, reconstructed, or modified after May 3, 2011, Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, residual oil, and petroleum coke.

* * * * *

Petroleum Coke, also known as *petcoke,* means a carbonization product of high-boiling hydrocarbon fractions obtained in petroleum processing (heavy

residues). Petroleum coke is typically derived from oil refinery coker units or other cracking processes.

* * * * *

Steam generating unit for facilities constructed, reconstructed, or modified before May 4, 2011, means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included). For units constructed, reconstructed, or modified after May 3, 2011, Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included) plus any integrated combustion turbines and fuel cells.

* * * * *

11. Revise § 60.42Da to read as follows:

§ 60.42Da Standard for particulate matter (PM).

(a) Except as provided in paragraph (a)(4) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before March 1, 2005, any gases that contain filterable PM in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(4) An owner or operator of an affected facility that combusts only gaseous or liquid fuels (excluding residual oil) with potential SO[2] emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and does not use a post-combustion technology to reduce emissions of SO[2] or PM is exempt from the PM standard specified in paragraphs (a)(1), (a)(2), and (a)(3) of this section:

(b) Except as provided in paragraphs (b)(1) and (b)(2) of this section, on and after the date the initial PM performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(1) Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart are exempt from the opacity standard specified in this paragraph (b) of this section.

(2) An owner or operator of an affected facility that combusts only natural gas is exempt from the opacity standard specified in paragraph (b) of this section.

(c) Except as provided in paragraphs (d) and (e) of this section, on and after the date on which the initial

performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain filterable PM in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, may elect to meet the requirements of this paragraph. For an affected facility that commenced construction, reconstruction, or modification, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator shall cause to be discharged into the atmosphere from that affected facility any gases that contain filterable PM in excess of:

(1) 13 ng/J (0.030 lb/MMBtu) heat input, and

(2) For an affected facility that commenced construction or reconstruction, 0.1 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.9 percent reduction) when combusting solid, liquid, or gaseous fuel, or

(3) For an affected facility that commenced modification, 0.2 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5)

(99.8 percent reduction) when combusting solid, liquid, or gaseous fuel.

(e) An owner or operator of an affected facility than combusts only gaseous or liquid fuels (excluding residual oil) with potential SO[2] emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and that does not use a post-combustion technology to reduce emissions of SO[2] or PM is exempt from the PM standard specified in paragraphs (c) of this section.

(f) Except as provided in paragraph (g) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, modification, or reconstruction after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain total PM in excess of either:

(1) For an affected facility that commenced construction or reconstruction 7.0 ng/J (0.055 lb/MWh) gross energy output; or

(2) For an affected facility that commenced modification, 15 ng/J (0.034 lb/MMBtu) heat input.

(g) An owner or operator of an affected facility that combusts only natural gas is exempt from the total PM standard specified in paragraph (f) of this section.

(h) The PM emission standards under this section do not apply to an owner or operator of any affected facility that is operated under a PM commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

12. Section 60.43Da is amended as follows:

a. By revising paragraphs (a)(1) through (a)(3).

b. By revising paragraph (f).

c. By revising paragraph (i).

d. By revising paragraph (j).

e. By revising paragraph (k).

f. By adding paragraph (a)(4).

g. By adding paragraph (l).

h. By adding paragraph (m).

i. By adding paragraph (n).

§ 60.43Da Standard for sulfur dioxide (SO2).

(a) * * *

(1) 520 ng/J (1.20 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction);

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input;

(3) 180 ng/J (1.4 lb/MWh) gross energy output; or

(4) 65 ng/J (0.15 lb/MMBtu) heat input.

* * * * *

(f) The SO[2] standards under this section do not apply to an owner or operator of an affected facility that is operated under an SO[2] commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

* * * * *

(i) Except as provided in paragraphs (j) and (k) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no

owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO[2] in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility which commenced construction, any gases that contain SO[2] in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 5 percent of the potential combustion concentration (95 percent reduction).

(2) For an affected facility which commenced reconstruction, any gases that contain SO[2] in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 5 percent of the potential combustion concentration (95 percent reduction).

(3) For an affected facility which commenced modification, any gases that contain SO[2] in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction).

(j) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no

owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO[2] in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

(1) For an affected facility which commenced construction, any gases that contain SO[2] in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 6 percent of the potential combustion concentration (94 percent reduction).

(2) For an affected facility which commenced reconstruction, any gases that contain SO[2] in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 6 percent of the potential combustion concentration (94 percent reduction).

(3) For an affected facility which commenced modification, any gases that contain SO[2] in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction).

(k) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area that commenced construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO[2] in excess of the applicable emission limitation specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO[2] in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO[2] in excess of 230 ng/J (0.54 lb/MMBtu) heat input.

(l) Except as provided in paragraphs (m) and (n) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO[2] in excess of the applicable emission limitation specified in paragraphs (l)(1) or (2) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain SO[2] in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 3 percent of the potential combustion concentration (97 percent reduction).

(2) For an affected facility which commenced modification, any gases that contain SO[2] in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 10 percent of the potential combustion concentration (90 percent reduction).

(m) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after May 3, 2011, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, shall caused to be discharged into the atmosphere from that affected facility any gases that contain SO[2] in excess of the applicable emission limitation specified in paragraphs (m)(1) or (2) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain SO[2] in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 6 percent of the potential combustion concentration (94 percent reduction).

(2) For an affected facility which commenced modification, any gases that contain SO[2] in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 10 percent of the potential combustion concentration (90 percent reduction).

(n) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area that commenced construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO[2] in excess of the applicable emission limitation specified in paragraphs (n)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO[2] in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO[2] in excess of 230 ng/J (0.54 lb/MMBtu) heat input.

13. Section 60.44Da is amended:

a. By revising paragraph (a) introductory text.

b. By revising paragraph (b).

c. By revising paragraph (d).

d. By revising paragraph (e).

e. By revising paragraph (f).

f. By adding paragraph (g).

g. By adding paragraph (h).

§ 60.44Da Standard for nitrogen oxides (NO).

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraphs (b), (d), (e), and (f) of this section, any gases that contain NO[X] (expressed as NO[2]) in excess of the following emission limits:

* * * * *

(b) The NO[X] emission limitations under this section do not apply to an owner or operator of an affected facility which is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

(d)(1) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction after July 9, 1997, but before March 1, 2005 shall cause to be discharged into the atmosphere any gases that contain NO[X] (expressed as NO[2]) in excess of 200 ng/J (1.6 lb/MWh) gross energy output, except as provided under § 60.48Da(k).

(2) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of affected facility for which reconstruction commenced after July 9, 1997, but

before March 1, 2005 shall cause to be discharged into the atmosphere any gases that contain NO[X] (expressed as NO[2]) in excess of 65 ng/J (0.15 lb/MMBtu) heat input.

(e) Except as provided in paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO[X] (expressed as NO[2]) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility which commenced construction, any gases that contain NO[X] (expressed as NO[2]) in excess of 130 ng/J (1.0 lb/MWh) gross energy output, except as provided under § 60.48Da(k).

(2) For an affected facility which commenced reconstruction, any gases that contain NO[X] (expressed as NO[2]) in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input.

(3) For an affected facility which commenced modification, any gases that contain NO[X] (expressed as NO[2]) in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input.

(f) On and after the date on which the initial performance test is completed or required to be

completed under § 60.8, whichever date comes first, the owner or operator of an IGCC electric utility steam generating unit subject to the provisions of this subpart and for which construction, reconstruction, or modification commenced after February 28, 2005 but before May 4, 2011, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) Except as provided for in paragraphs (f)(2) and (3) of this section, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO[X] (expressed as NO[2]) in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) When burning liquid fuel exclusively or in combination with solid-derived fuel such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO[X] (expressed as NO[2]) in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

(3) In cases when during a 30 boiler operating day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the clock hours in the 30-day period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO[X] (expressed as NO[2]) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

(g) Compliance with the emission limitations under this section are determined on a 30-boiler operating day rolling average basis, except as provided under § 60.48Da(j)(1).

(h) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO[X] (expressed as NO[2]) in excess of 88 ng/J (0.70 lb/MWh) gross energy output.

§ 60.45Da [Removed and Reserved]

14. Remove and reserve § 60.45Da.

15. Section 60.47Da is amended as follows:

a. By adding paragraph (f).

b. By adding paragraph (g).

c. By adding paragraph (h).

d. By adding paragraph (i).

Section 60.47Da Commercial demonstration permit.

* * * * *

(f) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the total PM emission reduction requirements under § 60.42Da but must, as a minimum, reduce PM emissions to less than 15 ng/J (0.034 lb/MMBtu) heat input.

(g) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the SO[2] standards or emission reduction requirements under § 60.43Da but must, as a minimum, reduce SO[2] emissions to 5 percent of the potential combustion concentration (95 percent reduction) or to less than 180 ng/J (1.4 lb/MWh) gross output on a 30 boiler operating day rolling average basis.

(h) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system or advanced combustion controls who is issued a commercial demonstration permit by the Administrator is not subject to the NO[X] standards or emission reduction requirements under § 60.44Da but must, as a minimum, reduce NO[X] emissions to less than 130 ng/J (1.0 lb/MWh) gross output on a 30 boiler operating day rolling average basis.

(i) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Multi-pollutant Emission Control	SO[2]	1,000
Multi-pollutant Emission Control	NO[X]	1,000

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Multi-pollutant Emission Control	PM	1,000
Pressurized Fluidized Bed Combustion	SO[2]	1,000
Pressurized Fluidized Bed Combustion	NO[X]	1,000
Pressurized Fluidized Bed Combustion	PM	1,000
Advanced Combustion Controls	NO[X]	1,000

16. Section 60.48Da is amended as follows:

a. By revising paragraph (c).

b. By revising paragraph (g).

c. By revising paragraph (k)(1)(i).

d. By revising paragraph (k)(1)(ii).

e. By revising paragraph (k)(2)(i).

f. By revising paragraph (k)(2)(iv).

g. By removing and reserving paragraph (l).

h. By revising paragraph (n).

i. By revising paragraphs (p)(5), (p)(7), and (p)(8).

j. By adding paragraph (r).

Section 60.48a Compliance provisions.

* * * * *

(c) For affected facilities that commenced construction, modification, or reconstruction before May 4, 2011, the PM emission standards under § 60.42Da, and the NO[X] emission standards under § 60.44Da apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide emission standards under § 60.43Da apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the procedures under paragraph (d) of this section are implemented. For affected facilities that commence construction, modification, or reconstruction after May 3, 2011, the PM emission standards under § 60.42Da, the NO[X] emission standards under § 60.44Da, and the sulfur dioxide emission standards under § 60.43Da apply at all times.

* * * * *

(g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

(1) For affected facilities that commenced construction, modification, or reconstruction before May 4, 2011, compliance with applicable 30 boiler operating day rolling average SO[2] and NO[X] emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO[2] and NO[X] for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO[X] only), or emergency conditions (SO[2] only). For affected facilities that commence construction, modification, or reconstruction after May 3, 2011, compliance with applicable 30 boiler operating day rolling average SO[2] and NO[X] emission limitations is determined by dividing the sum of all the SO[2] and NO[X] emissions for the 30

successive boiler operating days divided by the sum of all the gross useful output for the 30 successive boiler operating days.

(2) For affected facilities that commenced construction, modification, or reconstruction before May 4, 2011, compliance with applicable SO[2] percentage reduction requirements is determined based on the average inlet and outlet SO[2] emission rates for the 30 successive boiler operating days. For affected facilities that commence construction, modification, or reconstruction after May 3, 2011, compliance with applicable SO[2] percentage reduction requirements is determined based on the "as fired" total potential emissions and the total outlet SO[2] emissions for the 30 successive boiler operating days.

(3) For affected facilities that commenced construction, modification, or reconstruction before May 4, 2011 compliance with applicable daily average PM emission limitations is determined by calculating the arithmetic average of all hourly emission rates for PM each boiler operating day, except for data obtained during startup, shutdown, and malfunction. For affected facilities that commence construction, modification, or reconstruction after May 3, 2011, compliance with applicable daily average PM emission limitations is determined by calculating the sum of all PM emissions for PM each boiler operating day divided by the sum of all the gross useful output for PM each boiler operating day, except for data obtained during malfunction. Averages are only calculated for boiler operating days that have non-out-of-control data for at least 18 hours of unit operation during which the standard applies. Instead, all of the non-out-of-control hourly emission rates of the operating day(s) not meeting the minimum 18 hours non-out-of-control

data daily average requirement are averaged with all of the non-out-of-control hourly emission rates of the next boiler operating day with 18 hours or more of non-out-of-control PM CEMS data to determine compliance.

* * * * *

(k) * * *

(l) * * *

(i) The emission rate (E) of NO[X] shall be computed using Equation 2 in this section:

$$E = \frac{(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})}{(O_{sg} \times h)} \qquad \text{(Eq. 2)}$$

Where:

E = Emission rate of NO[X] from the duct burner, ng/J (lb/MWh) gross output;

C[sg] = Average hourly concentration of NO[X] exiting the steam generating unit, ng/dscm (lb/dscf);

C[te] = Average hourly concentration of NO[X] in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf);

Q[sg] = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr);

Q[te] = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr);

O[sg] = Average hourly gross energy output from steam generating unit, J/h (MW); and

h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

* * * * *

(2) * * *

(i) The emission rate (E) of NO[X] shall be computed using Equation 3 in this section:

$$E = \frac{(C_{sg} \times Q_{sg})}{O_{cc}} \quad \text{(Eq. 3)}$$

Where:

E = Emission rate of NO[X] from the duct burner, ng/J (lb/MWh) gross output;

C[sg] = Average hourly concentration of NO[X] exiting the steam generating unit, ng/dscm (lb/dscf);

Q[sg] = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr); and

O[cc] = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

* * * * *

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in § 60.49Da(l), determine the mass rate (lb/hr) of NO[X] emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of part 75 of this chapter. If this compliance option is selected, the emission rate (E) of NO[X] shall be computed using Equation 4 in this section:

$$E = \frac{(ER_{sg} \times H_{cc})}{O_{cc}} \quad \text{(Eq 4)}$$

Where:

E = Emission rate of NO[X] from the duct burner, ng/J (lb/MWh) gross output;

ER[sg] = Average hourly emission rate of NO[X] exiting the steam generating unit heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part, ng/J (lb/MMBtu);

H[cc] = Average hourly heat input rate of entire combined cycle unit, J/hr (MMBtu/hr); and

O[cc] = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

* * * * *

(n) Compliance provisions for sources subject to § 60.42Da(c)(1). The owner or operator of an affected facility subject to § 60.42Da(c)(1) shall calculate PM emissions by multiplying the average hourly PM output concentration (measured according to the provisions of § 60.49Da(t)), by the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), and divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)).

* * * * *

(p) * * *

(5) At a minimum, non-out-of-control valid CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30 boiler operating day rolling average basis. Beginning on January 1, 2012, non-out-of-control CEMS hourly averages shall be obtained for

90 percent of all operating hours on a 30 boiler operating day rolling average basis.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

* * * * *

(7) All non-out-of-control CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(5) of this section are not met.

(8) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator to provide, as necessary, non-out-of-control emissions data for a minimum of 90 percent (only 75 percent is required prior to January 1, 2012) of all operating hours per 30 boiler operating day rolling average.

* * * * *

(r) *Affirmative Defense for Exceedance of Emission Limit During Malfunction.* In response to an action to enforce the standards set forth in paragraph §§ 60.42Da, 60.43Da, and 60.44Da, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at *40 CFR 60.2*. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the

notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) The owner or operator of the facility experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standards in §§ 60.42Da, 60.43Da, and 60.44Da to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up

to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

17. Section 60.49Da is amended as follows:

a. By revising paragraphs (a)(1), (a)(2), and (a)(3) introductory text.

b. By revising paragraphs (b) introductory text and (b)(2).

c. By revising paragraph (e).

d. By revising paragraph (k) introductory text.

e. By revising paragraph (l).

f. By removing and reserving paragraph (p).

g. By removing and reserving paragraph (q).

h. By removing and reserving paragraph (r).

i. By revising paragraph (t).

j. By revising paragraphs (u)(1)(iii) and (u)(4).

§ 60.49Da Emission monitoring.

(a) * * *

(1) Except as provided for in paragraph (a)(2) of this section, the owner or operator of an affected facility subject to an opacity standard, shall install, calibrate, maintain, and operate a COMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example,

from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO[2] control system), alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(2) As an alternative to the monitoring requirements in paragraph (a)(1) of this section, an owner or operator of an affected facility that meets the conditions in either paragraph (a)(2)(i), (ii), (iii), or (iv) of this section may elect to monitor opacity as specified in paragraph (a)(3) of this section.

(i) The affected facility uses a fabric filter (baghouse) to meet the standards in § 60.42Da and a bag leak detection system is installed and operated according to the requirements in paragraphs § 60.48Da(o)(4)(i) through (v);

(ii) The affected facility burns only gaseous or liquid fuels (excluding residual oil) with potential SO[2] emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and does not use a post-combustion technology to reduce emissions of SO[2] or PM;

(iii) The affected facility meets all of the conditions specified in paragraphs (a)(2)(iii)(A) through (C) of this section; or

(A) No post-combustion technology (except a wet scrubber) is used for reducing PM, SO[2], or carbon monoxide (CO) emissions;

(B) Only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur are burned; and

(C) Emissions of CO discharged to the atmosphere are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis as demonstrated by the use of a CEMS measuring CO emissions according to the procedures specified in paragraph (u) of this section.

(iv) The affected facility uses an ESP and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part.

(3) The owner or operators of an affected facility that meets the conditions in paragraph (a)(2) of this section may, as an alternative to using a COMS, elect to monitor visible emissions using the applicable procedures specified in paragraphs (a)(3)(i) through (iv) of this section. The opacity performance test requirement in paragraph (a)(3)(i) must be conducted by April 29, 2011, within 45 days after stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later.

* * * * *

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO[2] emissions, except where natural gas and/or liquid fuels (excluding residual oil) with potential SO[2] emissions rates of 26 ng/J (0.060 lb/MMBtu) or less are the only fuels combusted, as follows:

* * * * *

(2) For a facility that qualifies under the numerical limit provisions of § 60.43Da SO[2] emissions are only monitored as discharged to the atmosphere.

* * * * *

(e) The CEMS under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction, and emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

* * * * *

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with an output-based standard.

* * * * *

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B of this part and the CD assessment, RATA and reporting provisions of procedure 1 of appendix F of this part, and record the output of the system, for measuring the volumetric flow rate of exhaust gases discharged to the atmosphere; or

* * * * *

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under § 60.42Da shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected facility demonstrating compliance with the input-based emission limitation in § 60.42Da may

install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) * * *

(1) * * *

(iii) At a minimum, non-out-of-control 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30 boiler operating day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

* * * * *

(4) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (i.e., reference method) data and performance test (i.e., compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/ert tool.html/) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFire database.

18. Section 60.50Da is amended as follows:

a. By revising paragraphs (b)(2) and (b)(4).

b. By removing paragraph (g).

c. By removing paragraph (h).

d. By removing paragraph (i).

§ 60.50Da Compliance determination procedures and methods.

* * * * *

(b) * * *

(2) For the filterable particular matter concentration, Method 5 of appendix A of this part shall be used at affected facilities without wet FGD systems and Method 5B of appendix A of this part shall be used after wet FGD systems.

* * * * *

(4) Total particular matter concentration consists of the sum of the filterable and condensable fractions. The condensable fraction shall be measured using Method 202 of appendix M of part 51, and the filterable fraction shall be measured using Method 5 of appendix A of this part.

* * * * *

19. Section 60.51Da is amended as follows:

a. By revising paragraph (a).

b. By removing and reserving paragraph (g).

c. By revising paragraph (k).

§ 60.51 Da Reporting requirements.

(a) For SO[2], NO[X], and PM emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

* * * * *

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO[2] and/or

NO[X] and/or opacity in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period.

§ 60.52Da(a) [Removed and reserved]

20. Section 60.52Da is amended by removing and reserving paragraph (a).

Subpart Db—[Amended]

21. Section 60.40b is amended as follows:

a. By revising paragraph (c).

b. By revising paragraph (h).

c. By revising paragraph (i).

d. By adding paragraph (1).

§ 60.40b Applicability and delegation of affected facility.

* * * * *

(c) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja (Standards of performance for petroleum refineries) are subject to the PM and NO[X] standards under this subpart and the SO[2] standards under subpart J or subpart Ja.

* * * * *

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, subpart AAAA, or subpart CCCC of this part is not subject to this subpart.

(i) Affected facilities (i.e. heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other affected facilities (i.e. heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the affected facility (i.e. heat recovery steam generator) is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

* * * * *

(l) Affected facilities that also meet the applicability requirements under subpart BB (Standards of Performance for Kraft Pulp Mills) are subject to the SO[2] and NO[X] standards under this subpart and the PM standards under subpart BB.

* * * * *

22. Section 60.41b is amended by revising the definition of "distillate oil" to read as follows:

§ 60.41b Definitions.

* * * * *

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined

by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosene, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

* * * * *

23. Section 60.44b is amended by revising paragraphs (c) and (d) to read as follows:

§ 60.44b Standard for nitrogen oxides (NO).

* * * * *

(c) Except as provided under paragraph (d) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO[X] in excess of the emission limit for the coal or oil, or mixtures of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable

requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas or distillate oil with a potential SO[2] emissions rate of 26 ng/J (0.060 lb/MMBtu) or less with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO[X] in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas, distillate oil, or a mixture of these fuels of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas, distillate oil, or a mixture of these fuels.

* * * * *

24. Section 60.46b is amended by revising paragraph (j)(14) to read as follows:

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

* * * * *

(j) * * *

(14) As of January 1, 2012, and within 60 days after the date of completing each performance test, as

defined in § 63.2, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (i.e., reference method) data and performance test (i.e., compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/ert tool.html/) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

25. Section 60.48b is amended as follows:

a. By revising paragraphs (a) introductory text and (a)(1)(i).

b. By revising paragraph (j) introductory text.

c. By revising paragraph (j)(5).

d. By revising paragraph (j)(6).

e. By adding paragraph (j)(7).

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who elects not to use a COMS shall conduct a

performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) * * *

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

* * * * *

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

* * * * *

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section § 60.48Da of this part; or

(6) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model

to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part; or

(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

* * * * *

Subpart Dc—[Amended]

26. Section 60.40c is amended as follows:

a. By revising paragraph (e).

b. By revising paragraph (f).

c. By revising paragraph (g).

§ 60.40c Applicability and delegation of authority.

* * * * *

(e) Affected facilities (i.e. heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/hr) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is

subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(f) Any facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements of and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

27. Section 60.41c is amended by removing the definition of "Cogeneration" and revising the definition of "Distillate oil" to read as follows:

§ 60.41c Definitions.

* * * * *

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosene, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

* * * * *

28. Section 60.42c is amended as follows:

a. By revising paragraph (d).

b. By revising paragraph (h) introductory text.

c. By revising paragraph (h)(3).

d. By adding paragraph (h)(4).

§ 60.42c Standard for sulfur dioxide (SO[2]).

* * * * *

(d) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO[2] in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

* * * * *

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f), as applicable.

* * * * *

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

* * * * *

29. Section 60.45c is amended by revising paragraph (c)(14) to read as follows:

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

* * * * *

(c)(14) As of January 1, 2012, and within 60 days after the date of completing each performance test, as defined in § 63.2, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (i.e., reference method) data and performance test (i.e., compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/ert tool.html/) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

* * * * *

30. Section 60.47c is amended as follows:

a. By revising paragraphs (a) introductory text and (a)(1)(i).

b. By revising paragraph (f).

c. By revising paragraph (g).

d. By adding paragraph (h).

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), (f), (g), and (h) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in § 60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), (f), or (g) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) * * *

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

* * * * *

(f) Owners and operators of an affected facility that is subject to an opacity standard in § 60.43c(c) and that uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section § 60.48Da of this part is not required to operate a COMS.

(g) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part.

(h) Owners and operators of an affected facility that is subject to an opacity standard in § 60.43c(c) and that burns only gaseous fuels and/or fuel oils that contain less than or equal to 0.5 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

Subpart HHHH—[Removed and Reserved]

31. Subpart HHHH is removed and reserved.

PART 63—[AMENDED]

32. The authority citation for part 63 continues to read as follows:

Authority: *42 U.S.C. 7401, et seq.*

33. Part 63 is amended by adding subpart UUUUU to read as follows:

Subpart UUUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Sec.

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Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

What This Subpart Covers

§ 63.9980 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs). This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

§ 63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU.

§ 63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of one or more new, reconstructed, and existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

(1) The affected source of this subpart is the collection of all existing coal- or oil-fired EGUs as defined in § 63.10042.

(2) The affected source of this subpart is each new or reconstructed coal- or oil-fired EGU as defined in § 63.10042.

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011, and you meet the applicability criteria at the time you commence construction.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after May 3, 2011, and you

meet the applicability criteria at the time you commence reconstruction.

(d) An EGU is existing if it is not new or reconstructed. An existing electric utility steam generating unit that has switched completely to burning a different coal rank or fuel type is considered to be an existing affected source under this subpart.

§ 63.9983 Are any EGUs not subject to this subpart?

The types of EGUs listed in paragraphs (a) through (c) of this section are not subject to this subpart.

(a) Any unit designated as a stationary combustion turbine, other than an integrated gasification combined cycle (IGCC), covered by 40 CFR part 63, subpart YYYY.

(b) Any EGU that is not a coal- or oil-fired EGU and combusts natural gas more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years.

(c) Any EGU that has the capability of combusting more than 73 MWe (250 million Btu/hr, MMBtu/hr) heat input (equivalent to 25 MWe output) of coal or oil but did not fire coal or oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years. Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such

as stationary gas turbines, internal combustion engines, and industrial boilers).

§ 63.9984 When do I have to comply with this subpart?

(a) If you have a new or reconstructed EGU, you must comply with this subpart by [DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**] or upon startup of your EGU, whichever is later.

(b) If you have an existing EGU, you must comply with this subpart no later than [3 YEARS AFTER DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**].

(c) You must meet the notification requirements in § 63.10030 according to the schedule in § 63.10030 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

Emission Limitations and Work Practice Standards

§ 63.9990 What are the subcategories of EGUs?

(a) Coal-fired EGUs are subcategorized as defined in paragraphs (a)(1) through (a)(2) of this section and as defined in § 63.10042.

(1) EGUs designed for coal >/= 8,300 Btu/lb, and

(2) EGUs designed for coal < 8,300 Btu/lb. (b) Oil-fired EGUs are subcategorized as noted in paragraphs (b)(1) through (b)(2) of this section and as defined in § 63.10042.

(1) EGUs designed to burn liquid oil, and

(2) EGUs designed to burn solid oil-derived fuel.

(c) IGCC units combusting either gasified coal or gasified solid oil-derived fuel. For purposes of compliance, monitoring, recordkeeping, and reporting requirements in this subpart, IGCC units are subject in the same manner as coal-fired units and solid oil-derived fuel-fired units, unless otherwise indicated.

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Table 1 through 3 to this subpart that applies to your EGU, for each EGU at your source, except as provided under paragraph (a)(1)(i) and (ii) or under § 63.10009.

(i) You may not use the alternate SO[2] limit if your coal-fired EGU does not have a system using wet or dry flue gas desulfurization technology installed on the unit.

(ii) You may not use the alternate SO[2] limit if your oil-fired EGU does not have a system using wet or dry flue gas desulfurization technology installed on the unit.

(iii) You must operate the wet or dry flue gas desulfurization technology installed on the unit at all times in order to qualify to use the alternate SO[2] limit.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your EGU. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to

establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(b) As provided in § 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

General Compliance Requirements

§ 63.10000 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(c)(1) For coal-fired units and solid oil-derived fuel-fired units, initial performance testing is required for all pollutants. For non-mercury HAP metals, you demonstrate continuous compliance through use of a particulate matter (PM) CEMS; initial compliance is determined by establishing an operational limit for filterable PM obtained during total PM emissions testing. As an alternative to using a PM CEMS, you

may demonstrate initial and continuous compliance by conducting total HAP metals testing or individual non-mercury (Hg) metals testing. For acid gases, you demonstrate initial and continuous compliance through use of a continuous hydrogen chloride (HCl) CEMS. As an alternative to HCl CEMS, you may demonstrate initial and continuous compliance by conducting performance testing. As another alternative to HCl CEMS, you may demonstrate initial and continuous compliance through use of a certified sulfur dioxide (SO[2]) CEMS, provided the unit has a system using wet or dry flue gas desulfurization technology. For mercury (Hg), if your unit does not qualify as a low emitting EGU (LEE), you must demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system.

(2) For liquid oil-fired units, you must demonstrate initial and continuous compliance for HCl, hydrogen fluoride (HF), and individual or total HAP metals by conducting performance testing. As an alternative to conducting performance testing, you may demonstrate compliance with the applicable emissions limit for HCl, HF, and individual or total HAP metals using fuel analysis provided the emission rate calculated according to § 63.10011(c) is less than the applicable emission limit.

(d) If you demonstrate compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), or through the use of a sorbent trap monitoring system for Hg, you must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before

your initial performance evaluation (where applicable) of your CMS or sorbent trap monitoring system. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B to part 60 or Part 75 of this chapter, and that meet the requirements of § 63.10010. The monitoring plan must address the provisions in paragraphs (d)(1) through (7) of this section.

(1) Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device).

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(3) Schedule for conducting initial and periodic performance evaluations.

(4) Performance evaluation procedures and acceptance criteria (e.g., calibrations), including ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d) or Appendix A to this subpart, as applicable.

(5) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii) or Appendix A to this subpart, as applicable.

(6) Conditions that define a continuous monitoring system that is out of control consistent with § 63.8(c)(7)(i) and for responding to out of control periods consistent with §§ 63.8(c)(7)(ii) and (c)(8) or Appendix A to this subpart, as applicable.

(7) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c), (e)(1), and (e)(2)(i) and Appendix A to this subpart, as applicable.

(e) You must operate and maintain the CMS or sorbent trap monitoring system according to the site-specific monitoring plan.

§ 63.10001 Affirmative Defense for Exceedence of Emission Limit During Malfunction.

In response to an action to enforce the standards set forth in paragraph § 63.9991 you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at *40 CFR 63.2*. Appropriate penalties may be assessed, however, if the respondent fails to meet its burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a limit, the owners or operators of facilities must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The excess emissions:

(i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and

monitoring equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(4) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(b) The owner or operator of the facility experiencing an exceedence of its emission limit(s) during a malfunction shall notify the EPA Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two (2) business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the EPA Administrator within 45 days of the initial occurrence of the exceedence of the standard in § 63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedances.

Testing, Fuel Analyses, and Initial Compliance Requirements

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) *General requirements.* Affected EGUs must demonstrate initial compliance with each of the applicable emissions limits in Tables 1 or 2 of this subpart through performance testing, along with one or more of the following activities: conducting a fuel analysis for each type of fuel combusted, establishing operating limits where applicable according to § 63.10011 and Table 7 to this subpart; conducting CMS performance evaluations where applicable; and conducting sorbent trap monitoring system performance evaluations, where applicable, in conjunction with performance testing. If you use a CMS that measures pollutant concentrations directly (i.e., a CEMS or a sorbent trap monitoring system), the performance test consists of the first 30 operating days of data collected with the certified monitoring system, after the applicable compliance date. If you use a continuous monitoring system that measures a surrogate for a pollutant (e.g., an SO[2] monitor), you must perform initial emission testing during the same compliance test period and under the same process (e.g., fuel) and control device operating conditions of the pollutant and surrogate, in addition to conducting the initial 30-day performance test. If you wish to demonstrate that a unit qualifies as a low emitting EGU (LEE), you must conduct performance testing in accordance with paragraphs (k) and (l) of this section.

(b) *Performance Testing Requirements.* Affected EGUs must demonstrate initial compliance with each of the applicable emissions limits in Tables 1 or 2 of

this subpart by conducting performance tests according to § 63.10007 and Table 5 to this subpart.

(1) For affected EGUs that do not rely on CMS, sorbent trap monitoring systems, or 28 to 30 day Method 30B testing to demonstrate initial compliance, performance test data and results from a prior performance test may be used to demonstrate initial compliance, provided the performance tests meet the following conditions:

(i) The performance test was conducted within the last twelve months;

(ii) The performance test was conducted in accordance with all requirements contained in § 63.10007 and Table 5 of this subpart; and

(iii) You certify, and have and keep documentation demonstrating, that the EGU configuration, control devices, and materials/fuel have remained constant since the prior performance test was conducted.

(2) [Reserved]

(c) *Fuel Analysis Requirements.* Affected liquid oil-fired EGUs may choose to demonstrate initial compliance with each of the applicable emissions limits in Tables 1 or 2 of this subpart by conducting a fuel analysis for each type of fuel combusted, except those affected EGUs that meet the exemptions identified in paragraphs (c)(4) and (5) of this section and those affected EGUs that opt to comply with the individual or total HAP metals limits in Tables 1 or 2 of this subpart which must comply by conducting a fuel analysis as described in paragraph (c)(1) of this section.

(1) For affected liquid oil-fired EGUs demonstrating compliance with the applicable emissions limits in

Tables 1 or 2 of this subpart for HCl or individual or total HAP metals through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your EGU according to § 63.10008 and Table 6 to this subpart and establish operating limits according to § 63.10011 and Table 8 to this subpart.

(2) For affected liquid oil-fired EGUs that elect to demonstrate compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for HF, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your EGU according to § 63.10008 and Table 6 to this subpart and establish operating limits according to § 63.10011 and Table 8 to this subpart.

(3) Fuel analysis data and results from a prior fuel analysis may be used to demonstrate initial compliance, provided the fuel analysis meets the following conditions:

(i) The fuel analysis was conducted within the last twelve months;

(ii) The fuel analysis was conducted in accordance with all requirements contained in § 63.10008 and Table 6 of this subpart; and

(iii) You certify, and have and keep documentation demonstrating, that the EGU configuration, control devices, and materials/fuel have remained constant since the prior fuel analysis was conducted.

(4) For affected EGUs that combust a single type of fuel, you are exempted from the initial compliance requirements of conducting a fuel analysis for each type of fuel burned in your EGU according to § 63.10008 and Table 6 to this subpart.

(5) For purposes of this subpart, EGUs that use a supplemental fuel only for startup, unit shutdown, or transient flame stability purposes qualify as affected EGUs that combust a single type of fuel, the supplemental fuel is not subject to the fuel analysis requirements under § 63.10008 and Table 6 to this subpart, and you are exempted from the initial compliance requirements of conducting a fuel analysis for each type of fuel burned in your EGU according to § 63.10008 and Table 6 to this subpart.

(d) *CMS Requirements.* (1) For affected liquid oil-fired EGUs that elect to demonstrate initial compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for HCl through use of HCl CEMS, initial compliance is determined using the average hourly HCl concentrations obtained during the first 30 day operating period after the monitoring system is certified.

(2) For affected liquid oil-fired EGUs that elect to demonstrate initial compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for HF through use of HF CEMS, initial compliance is determined using the average hourly HF concentrations obtained during the first 30 day operating period after the monitoring system is certified.

(3) For affected solid oil-derived fuel- or coal-fired EGUs that demonstrate initial compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for HCl through use of HCl CEMS, initial compliance is determined using the average hourly HCl concentrations obtained during the first 30 day operating period after the monitoring system is certified.

(4) For affected solid oil-derived fuel- or coal-fired EGUs with installed systems that use wet or dry flue gas desulfurization technology to demonstrate initial compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for SO[2] through use of SO[2] CEMS, initial compliance is determined using the average hourly SO[2] concentrations obtained during the first 30 day operating period after the monitoring system is certified.

(5) For affected solid oil-derived fuel- or coal-fired EGUs that demonstrate initial compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for PM through use of PM CEMS, initial compliance is determined using the average hourly PM concentrations obtained during the first 30 day operating period after the monitoring system is certified.

(6) For affected EGUs that demonstrate initial compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for Hg through use of Hg CEMS, initial compliance is determined using the average hourly Hg concentrations obtained during the first 30 day operating period after the monitoring system is certified.

(7) For affected EGUs that elect to demonstrate initial compliance with the applicable emissions limits in Tables 1 or 2 of this subpart for PM, non-Hg HAP metals, HCl, HF, or Hg through use of CPMS, initial compliance is determined using the average hourly PM, non-Hg HAP metals, HCl, HF, or Hg concentrations obtained during the first 30 day operating period.

(e) *Sorbent Trap Monitoring System Requirements.* For affected EGUs that demonstrate initial compliance with the applicable emissions limits in Tables 1

or 2 of this subpart for Hg through use of Hg sorbent trap monitoring system, initial compliance is determined using the average hourly Hg concentrations obtained during the first 30 day operating period.

(f) *Tune-ups.* For affected EGUs subject to work practice standards in Table 3 of this subpart, your initial compliance requirement is to conduct a tune-up of your EGU according to § 63.10021(a)(16)(i) through (vi).

(g) For existing affected sources, you must demonstrate initial compliance no later than 180 days after the compliance date that is specified for your source in § 63.9984 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart.

(h) If your new or reconstructed affected source commenced construction or reconstruction between May 3, 2011 and [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], you must demonstrate initial compliance with either the proposed emission limits or the promulgated emission limits no later than 180 days after [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**] or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(i) If your new or reconstructed affected source commenced construction or reconstruction between May 3, 2011, and [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], and you chose to comply with the proposed emission limits when demonstrating initial compliance, you must conduct a second

compliance demonstration for the promulgated emission limits within 3 years after [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**] or within 3 years after startup of the affected source, whichever is later.

(j) If your new or reconstructed affected source commences construction or reconstruction after [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], you must demonstrate initial compliance with the promulgated emission limits no later than 180 days after startup of the source.

(k) *Low emitting EGU.* Your existing EGU may qualify for low emitting EGU (LEE) status provided that initial performance test data that meet the requirements of § 63.10005(b) and paragraph (l) of this section demonstrate:

(1) With the exception of mercury, emissions less than 50 percent of the appropriate emissions limitation, or

(2) For mercury, emissions less than 10 percent of the mercury emissions limitation or less than 22.0 pounds per year. Only existing affected units may qualify for LEE status for Hg. When qualifying for LEE status for Hg emissions less than 22.0 pounds per year, the affected unit must also demonstrate compliance with the applicable emission limitation.

(3) The following provisions apply in demonstrating that a unit qualifies as a LEE. For all pollutants or surrogates except for Hg, conduct the initial performance tests as described in § 63.10007 but note that the required minimum sampling volume must be increased nominally by a factor of two; follow the instructions in Table 5 to this subpart to convert the

test data to the units of the applicable standard. For Hg, you must conduct a 28 to 30 operating day performance test, using Method 30B in appendix A-8 to part 60 of this chapter, to determine Hg concentration. Locate the Method 30B sampling probe tip at a point within the 10 percent centroidal area of the duct at a location that meets Method 1 in appendix A-8 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 28 to 30 day test period. You may not use a pair of sorbent traps to sample the stack gas for more than 10 days. Collect diluent gas data over the corresponding time period, and if preferred for calculation of pounds per year of Hg, stack flow rate data using Method 2 in appendix A-1 to part 60 of this chapter or a certified flow rate monitor and moisture data using Method 4 in appendix A-1 to part 60 of this chapter or a moisture monitor. Record parametric data during each performance test, to establish operating limits, in accordance with the applicable provisions of § 63.10010(k)(3). Calculate the average Hg concentration, in [mu]g/m<3>, for the 28 to 30 day performance test, as the arithmetic average of all sorbent trap results. Calculate the average CO[2] or O[2] concentration for the test period. Use the average Hg concentration and diluent gas values to express the performance test results in units of lb of Hg/TBtu, as described in section 6.2.1 of appendix A to this subpart, and, if elected, pounds of Hg per year, using the expected fuel input over a year period. You may also opt to calculate pounds of Hg per year using the average Hg concentration, average stack gas flow rate, average stack gas moisture, and maximum operating hours per year.

(1) Startup and Shutdown default values for calculations. For the purposes of this rule and only during periods of startup or shutdown, use a default

diluent gas concentration value of 10.0 percent O[2] or the corresponding fuel-specific CO[2] concentration in calculating emissions in units of lb/MMBtu or lb/TBtu. For calculating emissions in units of lb/MWh or lb/GWh only during startup or shutdown periods, use a nominal electrical production rate equal to 5 percent of rated capacity.

§ 63.10006 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) For solid oil-derived fuel- and coal-fired EGUs using total PM emissions as a surrogate for non-Hg HAP metals emissions and using PM CEMS to measure filterable PM emissions as a surrogate for total PM emissions, you must conduct all applicable performance tests for PM and non-Hg HAP metals emissions during the same compliance test period and under the same process (*e.g.*, fuel) and control device operating conditions according to Table 5 and § 63.10007 at least every 5 years.

(b) For solid oil-derived fuel- and coal-fired EGUs with installed systems that use wet or dry flue gas desulfurization technology using sulfur dioxide (SO[2]) emissions as a surrogate for HCl emissions and using SO[2] CEMS to measure SO[2] emissions, you must conduct all applicable performance tests for SO[2] and HCl emissions during the same compliance test period and under the same process (*e.g.*, fuel) and control device operating conditions according to Table 5 and § 63.10007 at least every 5 years.

(c) For affected units meeting the LEE requirements of § 63.1005(k), provided that the unit operates within the operating limits established during the initial performance test, you need only repeat the performance test once every 5 years according to Table 5 and

§ 63.10007 and conduct fuel sampling and analysis according to Table 6 and § 63.10008 at least every month. However, if the unit fails to operate within the operating limits during any 5 year compliance period, LEE status is lost. If this should occur:

(1) For all pollutants or surrogates except for Hg, you must initiate periodic emission testing, as required in the applicable paragraph(s) of this section, within a six month period.

(2) For Hg, you must install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with appendix A to this subpart, within a one year period.

(d) For solid oil-derived fuel- and coal-fired EGUs without PM CEMS but with PM emissions control devices, you must conduct all applicable performance tests for PM and non-Hg HAP metals emissions during the same compliance test period and under the same process (*e.g.*, fuel) and control device operating conditions according to Table 5 and § 63.10007 at least every year and you must conduct non-Hg HAP metals emissions testing according to Table 5 and § 63.10007 at least every other month.

(e) For solid oil-derived fuel- and coal-fired EGUs without PM CEMS and without PM emissions control devices, you must conduct all applicable performance tests for non-Hg HAP metals emissions according to Table 5 and § 63.10007 at least every month.

(f) For liquid oil-fired EGUs with non-Hg HAP metals control devices, you must conduct all applicable performance tests for individual or total HAP metals emissions according to Table 5 and § 63.10007 at least every other month.

(g) For liquid oil-fired EGUs without non-Hg HAP metals control devices, you must conduct all applicable performance tests for individual or total HAP metals emissions according to Table 5 and § 63.10007 at least every month.

(h) For solid oil-derived fuel- and coal-fired EGUs without SO[2] CEMS but with installed systems that use wet or dry flue gas desulfurization technology, you must conduct all applicable performance tests for SO[2] and HCl emissions during the same compliance test period and under the same process (*e.g.*, fuel) and control device operating conditions according to Table 5 and § 63.10007 at least every year and you must conduct SO[2] emissions testing according to § 63.10007 at least every other month.

(i) For solid oil-derived fuel- and coal-fired EGUs without SO[2] CEMS and without installed systems that use wet or dry flue gas desulfurization technology, you must conduct all applicable performance tests for SO[2] and HCl emissions during the same compliance test period and under the same process (*e.g.*, fuel) and control device operating conditions according to Table 5 and § 63.10007 at least every year and you must conduct HCl emissions testing according to Table 5 and § 63.10007 at least every month.

(j) For solid oil-derived fuel- and coal-fired EGUs without HCl CEMS but with HCl emissions control devices, you must conduct all applicable performance tests for HCl emissions according to Table 5 and § 63.10007 at least every other month.

(k) For solid oil-derived fuel- and coal-fired EGUs without HCl CEMS and without HCl emissions control devices, you must conduct all applicable performance

tests for HCl emissions according to Table 5 and § 63.10007 at least every month.

(l) For liquid oil-fired EGUs without HCl and HF CEMS but with HCl and HF emissions control devices, you must conduct all applicable performance tests for HCl and HF emissions according to Table 5 and § 63.10007 at least every other month.

(m) For liquid oil-fired EGUs without HCl and HF CEMS and without HCl and HF emissions control devices, you must conduct all applicable performance tests for HCl and HF emissions according to Table 5 and § 63.10007 at least every month.

(n) Unless you follow the requirements listed in paragraphs (o) through (q) of this section, performance tests required at least every 5 years must be completed within 58 to 62 months after the previous performance test; performance tests required at least every year must be completed no more than 13 months after the previous performance test; performance tests required at least every 2 months must be completed between 52 and 69 days after the previous performance test; and performance tests required at least every month must be completed between 21 and 38 days after the previous performance test.

(o) For EGUs with annual or more frequent performance testing requirements, you can conduct performance stack tests less often for a given pollutant if your performance stack tests for the pollutant for at least 3 consecutive years show that your emissions are at or below 50 percent of the emissions limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions. In this case, you do not have to conduct a performance test for that pollutant for the

next 2 years. You must conduct a performance test during the third year and no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.10009, you must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (m) of this paragraph.

(p) If your EGU continues to meet the emissions limit for the pollutant, you may choose to conduct performance stack tests for the pollutant every third year if your emissions are at or below the emission limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions, but each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.10009, you must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (m) of this paragraph.

(q) If a performance test shows emissions in excess of 50 percent of the emission limit, you must conduct performance tests at the appropriate frequency given in section (c) through (m) of this paragraph for that pollutant until all performance tests over a consecutive 3-year period show compliance.

(r) If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to § 63.10007. Each performance tune-up specified in § 63.10007 must be no more than 18 months after the previous performance tune-up.

(s) If you demonstrate compliance with the Hg, individual or total non-Hg HAP metals, HCl, or HF

emissions limit based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.10008 for each type of fuel burned. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your EGU. You must still meet all applicable continuous compliance requirements in § 63.10021.

(t) You must report the results of performance tests, performance tune-ups, and fuel analyses within 60 days after the completion of the performance tests, performance tune-ups, and fuel analyses. This report must also verify that the operating limits for your affected EGU have not changed or provide documentation of revised operating parameters established according to § 63.10011 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.10031.

§ 63.10007 What methods and other procedures must I use for the performance tests?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific test plan according to the requirements in § 63.7(c).

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that has the highest content of chlorine, fluorine, non-Hg HAP metals, and Hg, and you must demonstrate initial compliance and establish your operating limits based on these tests.

These requirements could result in the need to conduct more than one performance test. Moreover, should you desire to have differing operating limits which correspond to loads other than maximum normal operating load, you should conduct testing at those other loads to determine those other operating limits. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 of this subpart.

(d) For performance testing that does not involve CMS or a sorbent trap monitoring system, you must conduct three separate test runs for each performance test required, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 to this subpart. For performance testing that involves CMS or a sorbent trap monitoring system, compliance shall be determined as described in § 63.10005(d) and (e).

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, Appendix A-7 of this chapter to convert the measured PM concentrations, the measured HCl and HF concentrations, the measured SO[2] concentrations, the measured individual and total non-Hg HAP metals concentrations, and the measured Hg concentrations that result from the initial performance test to pounds per million Btu (lb/MMBtu) (pounds per trillion Btu, lb/TBtu, for Hg) heat input emission rates using F-factors.

(f) Performance tests shall be conducted under such conditions as the EPA Administrator specifies to the owner or operator based on representative performance of the affected source for the period being

tested. Upon request, the owner or operator shall make available to the EPA Administrator such records as may be necessary to determine the conditions of performance tests.

§ 63.10008 What fuel analyses and procedures must I use for the performance tests?

(a) You must conduct performance fuel analysis tests according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. You are not required to conduct fuel analyses for fuels used only for startup, unit shutdown, or transient flame stability purposes.

(b) You must develop and submit a site-specific fuel analysis plan to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section.

(1) You must submit the fuel analysis plan no later than 60 days before the date that you intend to demonstrate compliance.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each EGU.

(ii) For each fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location

that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine, fluorine, non-Hg HAP metals, or Hg.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal 1-hour intervals during the testing period.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a depth of 18 inches. You must insert a clean flat square shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break sample pieces larger than 3 inches into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (Hg, HAP metals, and/or chlorine) in units of lb/MMBtu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart.

§ 63.10009 May I use emission averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of § 63.9991 for PM, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis, if you have more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control), you may demonstrate compliance by emission averaging among the existing EGUs in the same subcategory, if your averaged emissions for such EGUs are equal to or less than the applicable emission limit, according to the procedures in this section.

(b) Separate stack requirements. For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, you may average PM, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (c), (d), (e), (f), and (g) of this section.

(c) For each existing EGU in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on

[*THE DATE 30 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE* **FEDERAL REGISTER**] or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on [*THE DATE 30 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE* **FEDERAL REGISTER**].

(d) The averaged emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified in § 63.9984.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum normal operating load of each EGU and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1 of this section to demonstrate that the PM, HF, SO[2], HCl, non-Hg HAP metals, or Hg emissions from all existing units participating in the emissions averaging option do not exceed the emission limits in Table 2 to this subpart.

$$\text{Ave Weighted Emissions} = \sum_{i=1}^{n} (Er \times Hm) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq. 1)}$$

Where:

Ave Weighted Emissions = Average weighted emissions for PM, HF, SO[2], HCl, non-Hg HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Er = Emissions rate (as determined during the most recent performance test, according to Table 5 to this subpart) for PM, HF, HCl, non-Hg HAP metals, or Hg

or by fuel analysis for Cl, F, non-Hg HAP metals, or Hg as calculated by the applicable equation in § 63.10011(c) for unit, i, for PM, HF, SO[2], HCl, non-Hg HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input, and the EGU generates steam for purposes other than generating electricity, you may use Equation 2 of this section as an alternative to using Equation 1 of this section to demonstrate that the PM, HF, HCl, non-Hg HAP metals, and Hg emissions from all existing units participating in the emissions averaging option do not exceed the emission limits in Table 2 to this subpart.

$$\text{Ave Weighted Emissions} = \sum_{i=1}^{n} (Er \times Sm \times CFi) \div \sum_{i=1}^{n} Sm \times CFi \qquad \text{(Eq. 2)}$$

Where:

Ave Weighted Emissions = Average weighted emission level for PM, HF, HCl, non-Hg HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Er = Emissions rate (as determined during the most recent performance test, according to Table 5 to this subpart) for PM, HF, HCl, non-Hg HAP metals, or Hg or by fuel analysis for Cl, F, non-Hg HAP metals, or Hg as calculated by the applicable equation in § 63.10011(c)) for unit, i, for PM, HCl, HF, HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Sm = Maximum steam generation by unit, i, in units of pounds.

Cf = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

n = Number of units participating in the emissions averaging option.

(f) You must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in § 63.9984.

(1) For each calendar month, you must use Equation 3 of this section to calculate the monthly average weighted emission rate using the actual heat capacity for each existing unit participating in the emissions averaging option.

$$\text{Ave Weighted Emissions} = \sum_{i=1}^{n} (Er \times Hb) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3)}$$

Where:

Ave Weighted Emissions = Monthly average weighted emission level for PM, HCl, HF, non-Hg HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Er = Emissions rate, (as determined during the most recent performance test, according to Table 5 to this subpart) for PM, HCl, HF, non-Hg HAP metals, or Hg or by fuel analysis for Cl, F, non-Hg HAP metals, or Hg as calculated by the applicable equation in § 63.10011(c)) for unit, i, for PM, HCl, HF, non-Hg HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Hb = The average heat input for each calendar month of EGU, i, in units of million Btu.

n = Number of units participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3 of this section to calculate the monthly weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

$$\text{Ave Weighted Emissions} = \sum_{i=1}^{n} (Er \times Sa \times Cfi) \div \sum_{i=1}^{n} Sa \times Cfi \qquad \text{(Eq. 4)}$$

Where:

Ave Weighted Emissions = Monthly average weighted emission level for PM, HCl, HF, HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Er = Emissions rate, (as determined during the most recent performance test, as calculated according to Table 5 to this subpart) for PM, HCl, HF, non-Hg HAP metals, or Hg or by fuel analysis for Cl, F, and non-Hg HAP metals, or Hg as calculated by the applicable equation in § 63.10011(c)) for unit, i, for PM, HCl, HF, non-Hg HAP metals, or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input.

Sa = Actual steam generation for each calendar month by EGU, i, in units of pounds.

Cf = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

n = Number of units participating in the emissions averaging option.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the monthly average weighted emission rate determined under paragraph (f)(1) or (2) of this section. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current month and the previous 11 months.

$$Eavg = \sum_{i=1}^{n} ERi \div 12 \qquad \text{(Eq. 5)}$$

Where:

Eavg = 12-month rolling average emissions rate, (lb/MMBtu heat input; lb/TBtu for Hg).

ERi = Monthly weighted average, for month "i" (lb/MMBtu (lb/TBtu for Hg) heat input)(as calculated by (f)(1) or (2)).

(g) You must develop, and submit to the applicable regulatory authority for review and approval upon request, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

(1) You must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing EGUs in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **Federal Register**] and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission EGU in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple EGUs, the owner or operator must identify each EGU;

(iv) The test plan for the measurement of PM, HF, HCl, individual or total non-Hg HAP metals, or Hg emissions in accordance with the requirements in § 63.10007;

(v) The operating parameters to be monitored for each control system or device consistent with § 63.9991 and Table 4, and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to § 63.10010, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the

frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the applicable regulatory authority, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating conditions.

(3) The regulatory authority shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable regulatory authority shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing unit in the same subcategory.

(h) *Common stack requirements.* For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM, HF, HCl, individual or total non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategory, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to paragraph (h) of this section, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in § 63.10007 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of equation 6.

$$En = \sum_{i=1}^{n} (ELi \times Hi) \div \sum_{i=1}^{n} Hi \qquad \text{(Eq. 6)}$$

Where:

En = HAP emissions limit, lb/MMBtu (lb/TBtu for Hg), ppm, or ng/dscm.

ELi = Appropriate emissions limit from Table 2 to this subpart for unit i, in units of lb/MMBtu (lb/TBtu for Hg), ppm, or ng/dscm.

Hi = Heat input from unit i, MMBtu.

n = Number of units.

(2) Conduct performance tests according to procedures specified in § 63.10007 in the common stack. If affected units from nonaffected units vent to the common stack,the units from nonaffected units must be shut down or vented to a different stack during the performance test or each affected and each

nonaffected unit must meet the most stringent emissions limit; and

(3) Meet the applicable operating limit specified in § 63.10021 and Table 8 to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) Combination requirements. The common stack of a group of two or more existing EGUs in the same subcategory subject to paragraph (h) of this section may be treated as a single stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) In some cases, existing affected units may exhaust through a common stack configuration or may include a bypass stack. Emission monitoring system installation provisions for possible stack configurations are as follows.

(1) *Single Unit-Single Stack Configuration.* For an affected unit that exhausts to the atmosphere through a single, dedicated stack, the owner or operator shall install CEMS and sorbent trap monitoring systems in accordance with the applicable performance specification or Appendix A to this subpart.

(2) *Unit Utilizing Common Stack with Other Affected Unit(s).* When an affected unit utilizes a common stack with one or more other affected units,

but no non-affected units, the owner or operator shall either:

(i) Install CEMS and sorbent trap monitoring systems described in this section in the duct to the common stack from each unit; or

(ii) Install CEMS and sorbent trap monitoring systems described in this section in the common stack.

(3) *Unit Utilizing Common Stack with Non-affected Units.* When one or more affected units shares a common stack with one or more non-affected units, the owner or operator shall either:

(i) Install CEMS and sorbent trap monitoring systems described in this section in the duct to the common stack from each affected unit; or

(ii) Install CEMS and sorbent trap monitoring systems described in this section in the common stack and attribute all of the emissions measured at the common stack to the affected unit(s).

(4) *Unit with a Main Stack and a Bypass Stack.* If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, the owner and operator shall install CEMS and the monitoring systems described in paragraph 2.1 of this section on both the main stack and the bypass stack.

(5) *Unit with Multiple Stack or Duct Configuration.* If the flue gases from an affected unit either: are discharged to the atmosphere through more than one stack; or are fed into a single stack through two or more ducts and the owner or operator chooses to monitor in the ducts rather than in the stack, the owner or operator shall either:

(i) Install CEMS and sorbent trap monitoring systems described in this section in each of the multiple stacks; or

(ii) Install CEMS and sorbent trap monitoring systems described in this section in each of the ducts that feed into the stack.

(b) If you use an oxygen (O[2]) or carbon dioxide (CO[2]) continuous emissions monitoring system (CEMS), install, operate, and maintain a CEMS for oxygen or carbon dioxide according to the procedures in paragraphs (b)(1) through (5) of this section by the compliance date specified in § 63.9984. The oxygen or carbon dioxide shall be monitored at the same location as the other pollutant CEMS, i.e., at the outlet of the EGU. Alternatively, an owner or operator may install, certify, maintain, operate and quality assure the data from an O[2] or CO[2] CEMS according to Appendix A of this subpart in lieu of the procedures in paragraphs (a)(1) through (a)(3) of this section.

(1) Install, operate, and maintain the O[2] or CO[2] CEMS according to the applicable procedures under Performance Specification (PS) 3 of 40 CFR part 60, Appendix B; and according to the applicable procedures under Quality Assurance Procedure 1 of 40 CFR part 60, Appendix F; and according to the site-specific monitoring plan developed according to § 63.10000(d).

(2) Conduct a performance evaluation of the CEMS according to the requirements in § 63.8 and according to PS 3 of 40 CFR part 60, Appendix B.

(3) Design and operate the CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) Reduce the CEMS data as specified in § 63.8(g)(2) and (4).

(5) Consistent with § 63.10020, calculate and record a 30 boiler operating day rolling average emissions rate on a daily basis. Daily, calculate a new 30 boiler operating day rolling average emissions rate as the average of all of the hourly oxygen emissions data for the preceding 30 boiler operating days.

(c) If you use an HCl CEMS, install, operate, and maintain a CEMS for HCl according to the procedures in paragraphs (c)(1) through (5) of this section by the compliance date specified in § 63.9984. The HCl shall be monitored at the outlet of the EGU.

(1) Install, operate, and maintain the CEMS according to the applicable procedures under Performance Specification (PS) 15 or 6 of 40 CFR part 60, Appendix B; and according to the applicable procedures under Quality Assurance Procedure 1 of 40 CFR part 60, Appendix F; and according to the site-specific monitoring plan developed according to § 63.10000(d).

(2) Conduct a performance evaluation of the CEMS according to the requirements in § 63.8 and according to PS 15 or 6 of 40 CFR part 60, Appendix B.

(3) Design and operate the CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) Reduce the CEMS data as specified in § 63.8(g)(2) and (4).

(5) Consistent with § 63.10020, calculate and record a 30 boiler operating day rolling average emissions rate on a daily basis. Daily, calculate a new 30 boiler

operating day rolling average emissions rate as the average of all of the hourly HCl emissions data for the preceding 30 boiler operating days.

(d) If you use an HF CEMS, install, operate, and maintain a CEMS for HF according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.9984. The HF shall be monitored at the outlet of the EGU.

(1) Install, operate, and maintain the CEMS according to the applicable procedures under Performance Specification (PS) 15 of 40 CFR part 60, Appendix B; and according to the applicable procedures under Quality Assurance Procedure 1 of 40 CFR part 60, Appendix F; and according to the site-specific monitoring plan developed according to § 63.10000(d).

(2) Conduct a performance evaluation of the CEMS according to the requirements in § 63.8 and according to PS 15 or 6 of 40 CFR part 60, Appendix B.

(3) Design and operate the CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) Reduce the CEMS data as specified in § 63.8(g)(2) and (4).

(5) Consistent with § 63.10020, calculate and record a 30 boiler operating day rolling average emissions rate on a daily basis. Daily, calculate a new 30 boiler operating day rolling average emissions rate as the average of all of the hourly HF emissions data for the preceding 30 boiler operating days.

(e) If you use an SO[2] CEMS, install, operate, and maintain a CEMS for SO[2] according to the

procedures in paragraphs (e)(1) through (5) of this section by the compliance date specified in § 63.9984. The SO[2] shall be monitored at the outlet of the EGU. Alternatively, for an affected source that is also subject to the SO[2] monitoring requirements of Part 75 of this chapter, the or operator may install, certify, maintain, operate and quality assure the data from an SO[2] CEMS according to Part 75 of this chapter in lieu of the procedures in paragraphs (g)(1) through (g)(3) of this section with the additional provisions of paragraph (g)(6).

(1) Install, operate, and maintain the CEMS according to the applicable procedures under Performance Specification (PS) 2 of 40 CFR part 60, Appendix B; and according to the applicable procedures under Quality Assurance Procedure 1 of 40 CFR part 60, Appendix F; and according to the site-specific monitoring plan developed according to § 63.10000(d).

(2) Conduct a performance evaluation of the CEMS according to the requirements in § 63.8 and according to PS 2 or 6 of 40 CFR part 60, Appendix B.

(3) Design and operate the CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) Reduce the CEMS data as specified in § 63.8(g)(2) and (4).

(5) Consistent with § 63.10020, calculate and record a 30 boiler operating day rolling average emissions rate on a daily basis. Daily, calculate a new 30 boiler operating day rolling average emissions rate is calculated as the average of all of the hourly SO[2] emissions data for the preceding 30 boiler operating days.

(6) When electing to use a Part 75 certified SO[2] CEMS to meet the requirements of this subpart, you must additionally meet the provisions listed in paragraphs (6)(i) through (6)(iii) below.

(i) You must perform the 7-day calibration error test required in appendix A to Part 75 on the SO[2] CEMS whether or not it has a span of 50 ppm or less.

(ii) You must perform the linearity check test required in appendix A to Part 75 on the SO[2] CEMS whether or not it has a span of 30 ppm or less.

(iii) The initial and quarterly linearity checks required under appendix A and appendix B of Part 75 must include a calibration gas (at a fourth level, if necessary) nominally at a concentration level equivalent to the applicable emission limit.

(f) If you use a Hg CEMS or a sorbent trap monitoring system for Hg, install, operate, and maintain the monitoring system in accordance with Appendix A to this subpart.

(g) If you use a PM CEMS, install, operate, and maintain a CEMS for PM according to the procedures in paragraphs (g)(1) through (6) of this section by the compliance date specified in § 63.9984. The PM shall be monitored at the outlet of the EGU.

(1) Install, operate, and maintain according to the applicable procedures under Performance Specification (PS) 11 of 40 CFR part 60, Appendix B; and according to the applicable procedures under Quality Assurance Procedure 2 of 40 CFR part 60, Appendix F; and according to the site-specific monitoring plan developed according to § 63.10000(d).

(2) Conduct a performance evaluation of the CEMS according to the requirements in § 63.8 and according to PS 11 of 40 CFR part 60, Appendix B.

(3) Design and operate the CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) Reduce the CEMS data as specified in § 63.8(g)(2) and (4).

(5) Consistent with § 63.10020, calculate and record a 30 boiler operating-day rolling average emissions rate on a daily basis. Daily, calculate a new 30 boiler operating day rolling average emissions rate is calculated as the average of all of the hourly particulate emissions data for the preceding 30 boiler operating days.

(h) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (h)(1) through (3) of this section by the compliance date specified in § 63.9984.

(1) Install, operate, and maintain each CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.10000(d) of this subpart and the design criteria and quality assurance and quality control procedures specified in paragraphs (h)(1) through (3) of this section. You may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (h)(1) through (3) of this section in your site-specific monitoring plan.

(2) Design and operate the CPMS to collect and record data measurements at least once every 15 minutes (see also § 63.10020), to reduce the measured values to a hourly averages or other appropriate period (e.g., instantaneous alarms) for calculating operating values in terms of the applicable averaging period, and to meet the specific CPMS requirements given in (i) through (v) of this section.

(i) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in (i)(A) through (D) of this section.

(A) Install the flow sensor and other necessary equipment in a position that provides a representative flow.

(B) Use a flow sensor with a measurement sensitivity of no greater than 2 percent of the expected flow rate.

(C) Minimize the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(D) Conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(ii) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in (ii)(A) through (F) of this section.

(A) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (e.g., PM scrubber pressure drop).

(B) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.

(C) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(D) Perform checks at least once each boiler operating day to ensure pressure measurements are not obstructed (e.g., check for pressure tap pluggage daily).

(E) Conduct a performance evaluation of the pressure measurement monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(F) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in your monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(iii) If you have an operating limit that requires a total secondary electric power monitoring system for an electrostatic precipitator (ESP), you must meet the requirements in (iii)(A) through (B) of this section.

(A) Install sensors to measure (secondary) voltage and current to the precipitator plates.

(B) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(iv) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in (iv)(A) through (B) of this section.

(A) Install each system in a position that provides a representative measurement of the total sorbent injection rate.

(B) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(v) If you have an operating limit that requires the use of a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate a bag leak detection system as specified in (v)(A) through (F) of this section.

(A) Install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(B) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(C) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see § 63.14).

(D) Use a bag leak detection system equipped with a device to continuously record the output signal from the sensor.

(E) Use a bag leak detection system equipped with a system that will alert when an increase in relative PM emissions over a preset level is detected. The alarm must be located where it can be detected and recognized easily by an operator.

(F) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.

(3) Conduct the CPMS equipment performance evaluations as specified in your site-specific monitoring plan.

§ 63.10011 How do I demonstrate initial compliance with the emission limits and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.10007, paragraph (c) of this section, and Tables 5 and 7 to this subpart.

(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.10007, Table 7 to this subpart, and paragraph (c)(6) of this section, as applicable. You must also conduct fuel analyses according to § 63.10008 and establish maximum fuel pollutant input levels according to paragraphs (c)(1) through (5) of this section, as applicable.

(1) You must establish the maximum chlorine fuel input (C[input]) during the initial performance testing according to the procedures in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your EGU that has the highest content of chlorine.

(ii) During the performance testing for HCl, you must determine the fraction of the total heat input for each fuel type burned (Q[i]) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (C[i]).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$Clinput = \sum_{i=1}^{n} (Ci \times Qi) \qquad \text{(Eq. 7)}$$

Where:

Clinput = Maximum amount of chlorine entering the EGU through fuels burned in units of lb/MMBtu.

Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to § 63.10008, in units of lb/MMBtu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your EGU for the mixture that has the highest content of chlorine.

(2) You must establish the maximum Hg fuel input level (Mercury[input]) during the initial performance testing using the procedures in paragraphs (c)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your EGU that has the highest content of Hg.

(ii) During the compliance demonstration for Hg, you must determine the fraction of total heat input for each fuel burned (Q[i]) based on the fuel mixture that has the highest content of Hg, and the average Hg concentration of each fuel type burned (HG[i]).

(iii) You must establish a maximum Hg input level using Equation 8 of this section.

$$Mercuryinput = \sum_{i=1}^{n} (HGi \times Qi) \quad \text{(Eq. 8)}$$

Where:

Mercuryinput = Maximum amount of Hg entering the EGU through fuels burned in units of lb/TBtu.

HGi = Arithmetic average concentration of Hg in fuel type, i, analyzed according to § 63.10008, in units of lb/TBtu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest Hg content. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your EGU for the mixture that has the highest content of Hg.

(3) You must establish the maximum non-Hg HAP metals fuel input level (HAP metal[input]) during the initial performance testing using the procedures in paragraphs (c)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your EGU that has the highest content of non-Hg HAP metals.

(ii) During the compliance demonstration for non-Hg HAP metals, you must determine the fraction of total heat input for each fuel burned (Q[i]) based on the fuel mixture that has the highest content of non-Hg HAP metals, and the average non-Hg HAP metals concentration of each fuel type burned (HAP metal[i]).

(iii) You must establish a maximum non-Hg HAP metal input level using Equation 9 of this section.

$$\text{HAP metalinput} = \sum_{i=1}^{n} (\text{HAP metali} \times \text{Qi}) \qquad \text{(Eq. 9)}$$

Where:

HAP metalinput = Maximum amount of non-Hg HAP metals entering the EGU through fuels burned in units of lb/MMBtu.

HAP metali = Arithmetic average concentration of non-Hg HAP metals in fuel type, i, analyzed according to § 63.10008, in units of lb/MMBtu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest non-Hg HAP metal content. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your EGU for the mixture that has the highest content of non-Hg HAP metals.

(4) You must establish the maximum fluorine fuel input (F[input]) during the initial performance testing according to the procedures in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your EGU that has the highest content of fluorine.

(ii) During the performance testing for HF, you must determine the fraction of the total heat input for each fuel type burned (Q[i]) based on the fuel mixture that has the highest content of fluorine, and the average fluorine concentration of each fuel type burned (F[i]).

(iii) You must establish a maximum fluorine input level using Equation 10 of this section.

$$Flinput = \sum_{i=1}^{n} (Fi \times Qi) \qquad \text{(Eq. 10)}$$

Where:

Fl input = Maximum amount of fluorine entering the EGU through fuels burned in units of lb/MMBtu.

Fi = Arithmetic average concentration of fluorine in fuel type, i, analyzed according to § 63.10008, in units of !b/MMBtu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your EGU for the mixture that has the highest content of fluorine.

(6) You must establish parameter operating limits according to paragraphs (c)(4)(i) through (v) of this section.

(i) For a wet PM scrubber, you must establish the minimum liquid flow rate and pressure drop as defined in § 63.10042, as your operating limits during the three-run performance test. If you use a wet PM scrubber and you conduct separate performance tests for PM, non-Hg HAP metals, or Hg emissions, you must establish one set of minimum liquid flow rate and pressure drop operating limits. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the highest minimum hourly average values established during the performance tests.

(ii) For a wet acid gas scrubber, you must establish the minimum liquid flow rate and pH as defined in § 63.10042, as your operating limits during the three-run performance test. If you use a wet acid gas scrubber and you conduct separate performance tests for HCl, HF, or SO[2] emissions, you must establish one set of minimum liquid flow rate and pH operating limits. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pH operating limits at the highest minimum hourly average values established during the performance tests.

(iii) For an electrostatic precipitator, you must establish the minimum hourly average secondary voltage and secondary amperage and calculate the total secondary power input as measured during the

three-run performance test and as defined in § 63.10042, as your operating limit.

(iv) For a dry scrubber or dry sorbent injection (DSI) system, you must establish the minimum hourly average sorbent injection rate for each sorbent, as measured during the three-run performance test and as defined in § 63.10042, as your operating.

(v) The operating limit for EGUs with fabric filters that choose to demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.10010, and that the sum duration of bag leak detection system alarms does not exceed 5 percent of the process operating time during a 6-month period.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.10008 and follow the procedures in paragraphs (c)(1) through (7) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your EGU that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided z-statistic test described in Equation 11 of this section.

$$P90 = mean + (SD \times t) \qquad \text{(Eq. 11)}$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in lb/MMBtu (lb/TBtu for Hg).

mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to § 63.10008, in units of lb/MMBtu (lb/TBtu for Hg).

SD = Standard deviation of the pollutant concentration in the fuel samples analyzed according to § 63.10008, in units of lb/MMBtu (lb/TBtu for Hg).

t = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your EGU using Equation 12 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} (Ci90 \times Qi \times 1.028) \qquad \text{(Eq. 12)}$$

Where:

HCl = HCl emissions rate from the EGU in units of lb/MMBtu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of lb/MMBtu as calculated according to Equation 12 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your EGU for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for Hg, the Hg emissions rate that you calculate for your EGU using Equation 13 of this section must not exceed the applicable emission limit for Hg.

$$\text{Mercury} = \sum_{i=1}^{n} (HGi90 \times Qi) \qquad \text{(Eq. 13)}$$

Where:

Mercury = Hg emissions rate from the EGU in units of lb/TBtu.

HGi90 = 90th percentile confidence level concentration of Hg in fuel, i, in units of lb/TBtu as calculated according to Equation 8 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest Hg content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your EGU for the mixture that has the highest Hg content.

(5) To demonstrate compliance with the applicable emission limit for non-Hg HAP metals, the non-Hg HAP metal emissions rate that you calculate for your EGU using Equation 14 of this section must not exceed the applicable emissions limit for non-Hg HAP metals.

$$\text{HAPmetals} = \sum_{i=1}^{n} (\text{HAPmetalsi90} \times Qi) \qquad \text{(Eq. 14)}$$

Where:

HAPmetals = Non-Hg HAP metals emission rate from the EGU in units of lb/MMBtu.

HAPmetalsi90 = 90th percentile confidence level concentration of non-Hg HAP metals in fuel, i, in units of lb/MMBtu as calculated according to Equation 9 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest non-Hg HAP metals content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your EGU for the mixture that has the highest non-Hg HAP metals content.

(6) To demonstrate compliance with the applicable emission limit for HF, the HF emissions rate that you calculate for your EGU using Equation 15 of this section must not exceed the applicable emission limit for HF.

$$HF = \sum_{i=1}^{n} (Fi90 \times Qi \times 1.053) \qquad \text{(Eq. 15)}$$

Where:

HF = HF emissions rate from the EGU in units of lb/MMBtu.

Fi90 = 90th percentile confidence level concentration of fluorine in fuel type, i, in units of lb/MMBtu as calculated according to Equation 7 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of fluorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your EGU for the mixture that has the highest content of fluorine.

1.053 = Molecular weight ratio of HF to fluorine.

(d) For units combusting coal or solid oil-derived fuel and electing to use PM as a surrogate for non-Hg HAP metals, you must install, certify, and operate PM CEMS in accordance with Performance Specification (PS) 11 in Appendix B to 40 CFR part 60, and to perform periodic, ongoing quality assurance (QA) testing of the CEMS according to QA Procedure 2 in Appendix F to 40 CFR Part 60. You must determine an operating limit (PM concentration in mg/dscm) during performance testing for initial PM compliance. The operating limit will be the average of the PM filterable results of the three Method 5 performance test runs. To determine continuous compliance, the hourly average PM concentrations will be averaged on a rolling 30 boiler operating day basis. Each 30 boiler operating day average would have to meet the PM operating limit.

(e) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.10030(e).

(f) If you are a LEE, the results of your initial performance test demonstrate your initial compliance.

Continuous Compliance Requirements

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10000(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (17) of this section.

(1) Following the date on which the initial performance test is completed or is required to be completed under §§ 63.7 and 63.10005, whichever date comes first, you must not operate above any of the applicable maximum operating limits or below any of the applicable minimum operating limits listed in Table 4 to this subpart at any time. Operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in § 63.10031(c), you must keep records of the type and amount of all fuels burned in each EGU during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would either result in lower emissions of HCl, HF, SO[2], non-Hg HAP metals, or Hg, than the applicable emission limit for each pollutant (if you demonstrate compliance through fuel analysis), or result in lower fuel input of chlorine, fluorine, sulfur, non-Hg HAP metals, or Hg than the maximum values calculated during the last performance tests (if you demonstrate compliance through performance stack testing).

(3) If you demonstrate compliance with an applicable HCl emissions limit through fuel analysis and you

plan to burn a new type of fuel, you must recalculate the HCl emissions rate using Equation 15 of § 63.10011 according to paragraphs (a)(3)(i) through (iii) of this section.

(i) You must determine the chlorine concentration for any new fuel type in units of lb/MMBtu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.10008(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emissions rate from your EGU under these new conditions using Equation 15 of § 63.10011. The recalculated HCl emissions rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emissions limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of § 63.10011. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.10011 are higher than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.10007 to demonstrate that the HCl emissions do not exceed the emissions limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.10011(b).

(5) If you are a liquid oil-fired EGU and demonstrate compliance with an applicable individual Hg emissions limit (rather than the total HAP metal emission

limit) through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the Hg emissions rate using Equation 11 of § 63.10011 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section.

(i) You must determine the Hg concentration for any new fuel type in units of lb/TBtu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.10008(b).

(ii) You must determine the new mixture of fuels that will have the highest content of Hg.

(iii) Recalculate the Hg emissions rate from your EGU under these new conditions using Equation 11 of § 63.10011. The recalculated Hg emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable Hg emissions limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum Hg input using Equation 8 of § 63.10011. If the results of recalculating the maximum Hg input using Equation 8 of § 63.10011 are higher than the maximum Hg input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.10007 to demonstrate that the Hg emissions do not exceed the emissions limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.10011(b).

(7) If you are a liquid oil-fired EGU and demonstrate compliance with an applicable HAP metals emission limit through fuel analysis, and you plan to burn a new

type of fuel, you must recalculate the HAP metals emission rate using Equation 14 of § 63.10011 according to the procedures specified in paragraphs (a)(7)(i) through (iii) of this section.

(i) You must determine the HAP metals concentration for any new fuel type in units of lb/MMBtu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.10008(b).

(ii) You must determine the new mixture of fuels that will have the highest content of HAP metals.

(iii) Recalculate the HAP metals emission rate from your EGU under these new conditions using Equation 14 of § 63.10011. The recalculated HAP metals emission rate must be less than the applicable emissions limit.

(8) If you demonstrate compliance with an applicable HAP metals emissions limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum HAP metals input using Equation 9 of § 63.10011. If the results of recalculating the maximum Hg input using Equation 9 of § 63.10011 are higher than the maximum HAP metals input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.10007 to demonstrate that the HAP metal emissions do not exceed the emissions limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.10011(b).

(9) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag

leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alarm and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the sum duration of alarms does not exceed 5 percent of the process operating time during a 6-month period. You must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time shall be counted as the actual amount of time taken to initiate corrective action.

(10) If you are required to install a CEMS according to § 63.10010(a), then you must meet the requirements in paragraphs (a)(10)(i) through (iii) of this section.

(i) You must continuously monitor oxygen according to §§ 63.10010(a) and 63.10020.

(ii) Keep records of oxygen levels according to § 63.10032(b).

(11) The owner or operator of an affected source using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (a)(11)(i) through (iv) of this section.

(i) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of § 60.13 of 40 CFR, Performance Specification 11 in Appendix B of 40 CFR part 60, and procedure 2 in Appendix F of 40 CFR part 60.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 in Appendix B of 40 CFR part 60, PM and O[2] (or CO[2]) data shall be collected concurrently (or within a 30- to 60-minute period) by both the CEMS and conducting performance tests using Method 5 or 5D of Appendix A-3 of 40 CFR part 60.

(iii) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in Appendix F of this chapter. Relative Response Audits must be performed annually and Response Correlation Audits must be performed every 3 years.

(iv) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2 and as required in this subpart, you must submit performance test data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/ert_tool.html/). Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(v) Within 60 days after the date of completing each CEMS performance evaluation test, as defined in § 63.2 and required by this subpart, you must submit the relative accuracy test audit data electronically into EPA's Central Data Exchange by using the Electronic

Reporting Tool as mentioned in paragraph (11)(iv) of this section. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(vi) All reports required by this subpart not subject to the requirements in paragraphs (11)(iv) and (v) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraph (11)(iv) and (v) of this section in paper format.

(12) The owner or operator of an affected source using a CEMS measuring HCl emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (a)(12)(i) through (iii) of this section.

(i) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of § 60.13 of 40 CFR, Performance Specifications 6 or 15 in Appendix B of 40 CFR part 60, and procedure 2 in Appendix F of 40 CFR part 60.

(ii) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 1 in Appendix F of 40 CFR part 60.

(13) The owner or operator of an affected source using a CEMS measuring SO[2] emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (a)(13)(i) through (iii) of this section.

(i) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of § 60.13 of 40 CFR part 60, Performance Specification 2 or 6 in Appendix B of 40 CFR part 60, and procedure 1 in Appendix F of 40 CFR part 60.

(ii) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 1 in Appendix F of 40 CFR part 60.

(14) The owner or operator of an affected source using a CEMS measuring Hg emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (a)(14)(i) through (iii) of this section.

(i) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of Appendix A of this subpart.

(ii) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 5 in Appendix F of 40 CFR part 60.

(15) As an alternative to measuring Hg emissions using Hg CEMS, the owner or operator of an affected source using a sorbent trap monitoring system to meet requirements of this subpart shall install, certify, operate, and maintain the sorbent trap monitoring system in accordance with Appendix A to this subpart.

(16) You must conduct a performance tune-up of the EGU to demonstrate continuous compliance as specified in paragraphs (a)(16)(i) through (a)(16)(vii) of this section.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary you may delay the burner inspection until the next

scheduled unit shutdown, but you must inspect each burner at least once every 18 months);

(ii) Inspect the flame pattern, as applicable, and make any adjustments to the burner necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly;

(iv) Optimize total emissions of CO and NO[X]. This optimization should be consistent with the manufacturer's specifications, if available;

(v) Measure the concentration in the effluent stream of CO and NO[X] in ppm, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made); and

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(16)(vi)(A) through (C) of this section,

(A) The concentrations of CO and NO[X] in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after the adjustments of the EGU;

(B) A description of any corrective actions taken as a part of the combustion adjustment; and

(C) The type and amount of fuel used over the 12 months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period.

(vii) After December 31, 2011, and within 60 days after the date of completing each performance tune-up conducted to demonstrate compliance with this subpart, you must submit a notice of completion of the performance tune-up to EPA by successfully submitting the data electronically into an EPA database.

(17) For LEEs, the results of your initial and subsequent emissions tests, along with records of your fuel analyses, demonstrate your continuous compliance and continued eligibility as a LEE.

(i) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2 and as required in this subpart, you must submit performance test data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/ert_tool.html/). Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(ii) Within 60 days after the date of completing each CEMS performance evaluation test, as defined in 63.2 and required by this subpart, you must submit the relative accuracy test audit data electronically into EPA's Central Data Exchange by using the Electronic Reporting Tool as mentioned in paragraph (17)(i) of this section. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(iii) All reports required by this subpart not subject to the requirements in paragraphs (17)(i) and (ii) of this section must be sent to the Administrator at the

appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraph (17)(i) and (ii) of this section in paper format.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 to this subpart that apply to you. These instances are deviations from the emission limits in this subpart. These deviations must be reported according to the requirements in § 63.10031.

(c) Consistent with § 63.10010, § 63.10020, and your site-specific monitoring plan, you must determine the 3-hour rolling average of the CPMS data collected for all periods the process is operating.

§ 63.10022 How do I demonstrate continuous compliance under the emission averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (8) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.10009(f) and (g);

(2) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber for PM control, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test;

(3) For each existing unit participating in the emissions averaging option that is equipped with a fabric filter but without PM CEMS, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test;

(4) For each existing unit participating in the emissions averaging option that is equipped with dry sorbent injection, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test;

(5) For each existing unit participating in the emissions averaging option that is equipped with an ESP, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test;

(6) For each existing unit participating in the emissions averaging option that is equipped with an ESP, maintain the monthly fuel content values at or below the operating limits established during the most recent performance test;

(7) For each existing unit participating in the emissions averaging option that has an approved alternative operating plan, maintain the 3-hour average parameter values at or below the operating limits established in the most recent performance test.

(8) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (8) of this section is a deviation.

Notification, Reports, and Records

§ 63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], you must submit an Initial Notification not later than 120 days after [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**].

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in § 63.10011(a), you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each initial compliance demonstration, you must submit the Notification

of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of the performance test and/or other initial compliance demonstrations according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (6), as applicable.

(1) A description of the affected source(s) including identification of which subcategory the source is in, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under *40 CFR 241.3*, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of *40 CFR 241.3*, and justification for the selection of fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing and fuel analysis; performance testing with operational limits (e.g., CEMS for surrogates or CPMS); CEMS; or sorbent trap monitoring system.

(4) Identification of whether you plan to demonstrate compliance by emissions averaging.

(5) A signed certification that you have met all applicable emission limits and work practice standards.

(6) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

(7) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following certification of compliance and must be signed by a responsible official:

(i) "This EGU complies with the requirement in § 63.10021(a)(16)(i) through (vi)."

§ 63.10031 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.9984 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in § 63.9984.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.9984.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to *40 CFR 70.6(a)(3)(iii)(A)* or *40 CFR 71.6(a)(3)(iii)(A)*, you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (9) of this section.

(1) Company name and address.

(2) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or

your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(5) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every three years consistent with § 63.10006(o) or (p), the date of the last three stack tests, a comparison of the emission level you achieved in the last three stack tests to the 50 percent emission limit threshold required in § 63.10006(o) or (p), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(6) A signed statement indicating that you burned no new types of fuel. Or, if you did burn a new type of fuel, you must submit the calculation of chlorine input, using Equation 7 of § 63.10011, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 15 of § 63.10011 that demonstrates that your source is still meeting the emission limit for HCl emissions (for EGUs that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of Hg input, using Equation 8 of § 63.10011, that demonstrates that your source is still within its maximum Hg input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of Hg emission rate using Equation 11 of § 63.10011 that demonstrates that your source is still

meeting the emission limit for Hg emissions (for EGUs that demonstrate compliance through fuel analysis).

(7) If you wish to burn a new type of fuel and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.10011 or the maximum Hg input operating limit using Equation 8 of § 63.10011, you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(8) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(9) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, and CPMS, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(10) Include the date of the most recent tune-up for each unit subject to the requirement to conduct a performance tune-up according to § 63.10021(a)(16)(i) through (vi). Include the date of the most recent burner inspection if it was not done annually and was delayed until the next scheduled unit shutdown.

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an affected source where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the

information required in paragraphs (d)(1) through (4) of this section.

(1) The total operating time of each affected source during the reporting period.

(2) A description of the deviation and which emission limit or operating limit from which you deviated.

(3) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(4) A copy of the test report if the annual performance test showed a deviation from the emission limits.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in paragraphs (e)(1) through (12) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.10000(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred

during a period of startup, shutdown, or malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) An analysis of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMSs downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) An identification of each parameter that was monitored at the affected source for which there was a deviation.

(9) A brief description of the source for which there was a deviation.

(10) A brief description of each CMS for which there was a deviation.

(11) The date of the latest CMS certification or audit for the system for which there was a deviation.

(12) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by *40 CFR 70.6(a)(3)(iii)(A)* or *40 CFR*

71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 9 to this subpart along with, or as part of, the semiannual monitoring report required by *40 CFR 70.6(a)(3)(iii)(A)* or *40 CFR 71.6(a)(3)(iii)(A)*, and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) In addition to the information required in § 63.9(h)(2), your notification must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(1) "This facility complies with the requirements in § 63.10021(a)(10) to conduct an annual performance test of the unit"

(2) "No secondary materials that are solid waste were combusted in any affected unit."

(h)(1) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2 and as required in this subpart, you must submit performance test data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/ert_tool.html/). Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(2) Within 60 days after the date of completing each CEMS performance evaluation test, as defined in 63.2 and required by this subpart, you must submit the relative accuracy test audit data electronically into EPA's Central Data Exchange by using the Electronic Reporting Tool as mentioned in paragraph (h)(1) of this section. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(3) All reports required by this subpart not subject to the requirements in paragraphs (h)(1) and (2) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraph (h)(1) and (2) of this section in paper format.

(i) If you had a malfunction during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.10000(b), including actions taken to correct a malfunction.

§ 63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) through (2) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all

documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in § 63.10(b)(2)(viii).

(b) For each CEMS and CPMS, you must keep records according to paragraphs (b)(1) through (4) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (i.e., superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits such as pressure drop and pH to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each EGU subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (5) of this section.

(1) You must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to *40 CFR 241.3(b)(1)*, you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a non-fuel that has been processed from a discarded non-hazardous secondary material pursuant to *40 CFR 241.3(b)(2)*, you must keep records as to how the operations that produced the fuel satisfies the definition of processing in *40 CFR 241.2*. If the fuel received a non-waste determination pursuant to the petition process submitted under *40 CFR 241.3(c)*, you must keep a record which documents how the fuel satisfies the requirements of the petition process.

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.10011, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 15 of § 63.10011, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple EGUs provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each EGU.

(4) A copy of all calculations and supporting documentation of maximum Hg fuel input, using Equation 8 of § 63.10011, that were done to demonstrate

continuous compliance with the Hg emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of Hg emission rates, using Equation 11 of § 63.10011, that were done to demonstrate compliance with the Hg emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum Hg fuel input or Hg emission rates. You can use the results from one fuel analysis for multiple EGUs provided they are all burning the same fuel type. However, you must calculate Hg fuel input, or Hg emission rates, for each EGU.

(5) If consistent with § 63.10032(b) and (c), you choose to stack test less frequently than annually, you must keep annual records that document that your emissions in the previous stack test(s) were less than 90 percent of the applicable emission limit, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.

(e) If you elect to average emissions consistent with § 63.10009, you must additionally keep a copy of the emission averaging implementation plan required in § 63.10009(g), all calculations required under § 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.10022.

(f) Records of the occurrence and duration of each startup and/or shutdown.

(g) Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.

(h) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

§ 63.10033 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§ 63.10040 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.10041 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency; however, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.9991(a) and (b) under § 63.6(g).

(2) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, approval of minor and intermediate changes to monitoring performance specifications/procedures in Table 5 where the monitoring serves as the performance test method (see definition of "test method" in § 63.2), and approval of alternative analytical methods requested under § 63.10008(b)(2).

(3) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and approval of alternative operating parameters under §§ 63.9991(a)(2) and 63.10009(g)(2).

(4) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

§ 63.10042 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in § 63.2 (the General Provisions), and in this section as follows:

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Anthracite coal means solid fossil fuel classified as anthracite coal by American Society of Testing and Materials (ASTM) Method D388-77, 90, 91, 95, 98a, or 99 (incorporated by reference, see *40 CFR 63.14(b)(39)*).

Bag leak detection system means a group of instruments that are capable of monitoring PM loadings in the exhaust of a fabric filter (i.e., baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative PM loadings.

Bituminous coal means coal that is classified as bituminous according to ASTM Method D388-77, 90, 91, 95, 98a, or 99 (Reapproved 2004) <e1> (incorporated by reference, see *40 CFR 63.14(b)(39)*).

Boiler operating day means a 24-hour period between midnight and the following midnight during which any fuel is combusted at any time in the steam

generating unit. It is not necessary for the fuel to be combusted the entire 24-hour period.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM Method D388-991<1> (incorporated by reference, see *40 CFR 63.14(b)(39)*), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (not meeting the definition of natural gas), solvent-refined coal, coal-oil mixtures, and coal-water mixtures, are considered "coal" for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns coal or coal refuse either exclusively, in any combination together, or in any combination with other fuels in any amount.

Coal refuse means any by-product of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

Cogeneration means a steam-generating unit that simultaneously produces both electrical (or mechanical) and useful thermal energy from the same primary energy source.

Cogeneration unit means a stationary, fossil fuel-fired EGU meeting the definition of "fossil fuel-fired" or stationary, integrated gasification combined cycle:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

Combined-cycle gas stationary combustion turbine means a stationary combustion turbine system where heat from the turbine exhaust gases is recovered by a waste heat boiler.

Common stack means the exhaust of emissions from two or more affected units through a single flue.

Deviation. (1) Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, work practice standard, or monitoring requirement; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM Method D396-02a (incorporated by reference, see § 63.14(b)(40)).

Dry flue gas desulfurization technology, or *dry FGD,* or spray dryer absorber (SDA), or *spray dryer,* or *dry scrubber* means an add-on air pollution control system located downstream of the steam generating unit that injects a dry alkaline sorbent (dry sorbent injection) or sprays an alkaline sorbent slurry (spray dryer) to react with and neutralize acid gases such as SO[2] and HCl in the exhaust stream forming a dry powder material. Sorbent injection systems in fluidized bed combustors (FBC) or circulating fluidized bed (CFB) boilers are included in this definition.

Dry sorbent injection (DSI) means an add-on air pollution control system in which sorbent (e.g., conventional activated carbon, brominated activated carbon, Trona, hydrated lime, sodium carbonate, etc.) is injected into the flue gas steam upstream of a PM

control device to react with and neutralize acid gases (such as SO[2] and HCl) or Hg in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Electrostatic precipitator or *ESP* means an add-on air pollution control device that is located downstream of the steam generating unit used to capture PM by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

Emission limitation means any emissions limit or operating limit.

Equivalent means the following only as this term is used in Table 6 to subpart UUUUU:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the Hg, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an "as received" basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (Hg) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to subpart UUUUU for the same purpose.

Fabric filter, or *FF,* or *baghouse* means an add-on air pollution control device that is located downstream of

the steam generating unit used to capture PM by filtering gas streams through filter media.

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including the requirements of 40 CFR parts 60, 61, and 63; requirements within any applicable State implementation plan; and any permit requirements established under *40 CFR 52.21* or under 40 CFR 51.18 and 40 CFR 51.24.

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of combusting more than 73 MWe (250 million Btu/hr, MMBtu/hr) heat input (equivalent to 25 MWe output) of fossil fuels. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in their permits and have the appropriate fuel handling facilities on-site (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Fluidized bed boiler, or *fluidized bed combustor,* or *circulating fluidized boiler,* or *CFB* means a boiler utilizing a fluidized bed combustion process.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles which are maintained in a mobile suspension by the forward flow of air and combustion products.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, solid oil-derived gas, refinery gas, and biogas. Blast furnace gas is exempted from this definition.

Generator means a device that produces electricity.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls), or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in an EGU and does not include the heat input from preheated combustion air, recirculated flue

gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, etc.

Integrated gasification combined cycle electric utility steam generating unit or *IGCC* means an electric utility steam generating unit that burns a synthetic gas derived from coal or solid oil-derived fuel in a combined-cycle gas turbine. No coal or solid oil-derived fuel is directly burned in the unit during operation.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite coal means coal that is classified as lignite A or B according to ASTM Method D388-77, 90, 91, 95, 98a, or 99 (Reapproved 2004)[epsilon]<1> (incorporated by reference, see § 63.14(a)(39)).

Liquid fuel includes, but is not limited to, distillate oil and residual oil.

Minimum pressure drop means 90 percent of the test average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber effluent pH means 90 percent of the test average effluent pH measured at the outlet of the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable HCl emission limit.

Minimum scrubber flow rate means 90 percent of the test average flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means 90 percent of the test average sorbent (or activated carbon) injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Minimum voltage or *amperage* means 90 percent of the test average voltage or amperage to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by ASTM Method D1835-03a (incorporated by reference, see § 63.14(b)(41)).

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Non-cogeneration unit means a unit that has a combustion unit of more than 25 MWe and that supplies more than 25 MWe to any utility power distribution system for sale.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Non-mercury (Hg) HAP metals means Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd),

Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se).

Oil means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, solid oil-derived fuel (e.g., petroleum coke) and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

Oil-fired electric utility steam generating unit means an electric utility steam generating unit that either burns oil exclusively, or burns oil alternately with burning fuels other than oil at other times.

Particulate matter or *PM* means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an alternative method.

Pulverized coal boiler means an EGU in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the EGU where it is fired in suspension.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by ASTM Method D396-02a (incorporated by reference, see § 63.14(b)(40)).

Responsible official means responsible official as defined in *40 CFR 70.2*.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle station-

ary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included).

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit undergrate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. There are two general types of stokers: underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers.

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to ASTM Method D388-77, 90, 91, 95, 98a, or 99 (Reapproved 2004) [epsilon]<1> (incorporated by reference, see § 60.14(a)(39)).

Unit designed for coal > 8,300 Btu/lb subcategory includes any EGU designed to burn a coal having a calorific value (moist, mineral matter-free basis) of

greater than or equal to 19,305 kilojoules per kilogram (kJ/kg) (8,300 British thermal units per pound (Btu/lb)) in an EGU with a height-to-depth ratio of less than 3.82.

Unit designed for coal < 8,300 Btu/lb includes any EGU designed to burn a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) in an EGU with a height-to-depth ratio of 3.82 or greater.

Unit designed to burn liquid oil fuel subcategory includes any EGU that burned any liquid oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years, either alone or in combination with gaseous fuels.

Unit designed to burn solid oil-derived fuel subcategory includes any EGU that burned a solid fuel derived from oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years, either alone or in combination with other fuels.

Voluntary Consensus Standards or *VCS* mean technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN

or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: The U.S. States, e.g., California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, e.g. Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Wet flue gas desulfurization technology, or *wet FGD,* or *wet scrubber* means any add-on air pollution control device that is located downstream of the steam generating unit that mixes an aqueous stream or slurry with the exhaust gases from an EGU to control emissions of PM and/or to absorb and neutralize acid gases, such as SO[2] and HCl.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to CAA section 112(h).

Tables to Subpart UUUUU of Part 63

As stated in § 63.9991, you must comply with the following applicable emission limits:

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate, (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
1. Coal-fired unit designed for coal >/= 8,300 Btu/lb	a. Total particulate matter (PM)	0.050 lb per MWh	Collect a minimum of 4 dscm per run.
	OR Total non-Hg HAP metals	OR 0.000040 lb per MWh	Collect a minimum of 4 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.000080 lb/GWh	
	Arsenic (As)	0.00020 lb/GWh	
	Beryllium (Be)	0.000030 lb/GWh	

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate, (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	Cadmium (Cd)	0.00040 lb/GWh	
	Chromium (Cr)	0.020 lb/GWh	
	Cobalt (Co)	0.00080 lb/GWh	
	Lead (Pb)	0.00090 lb/GWh	
	Manganese (Mn)	0.0040 lb/GWh	
	Nickel (Ni)	0.0040 lb/GWh	
	Selenium (Se)	0.030 lb/GWh	
	b. Hydrogen chloride (HCl)	0.30 lb per GWh	For Method 26A, collect a minimum of 4 dscm per run.
	OR		
	Sulfur dioxide	0.40 lb per MWh	SO2 CEMS.

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

If your EGU is in this subcategory . .	For the following pollutants . .	You must meet the following emission limits and work practice standards . .	Using these requirements, as appropriate, (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . .
	(SO2)(1M)		
	c. Mercury (Hg)	0.000010 lb per GWh	Hg CEMS or Sorbent trap monitoring system.
2. Coal-fired unit designed for coal < 8,300 Btu/lb	a. Total particulate matter (PM)	0.050 lb per MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	0.000040 lb per MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.000080 lb/GWh	

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . .	Using these requirements, as appropriate, (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	Arsenic (As)	0.00020 lb/GWh	
	Beryllium (Be)	0.000030 lb/GWh	
	Cadmium (Cd)	0.00040 lb/GWh	
	Chromium (Cr)	0.020 lb/GWh	
	Cobalt (Co)	0.00080 lb/GWh	
	Lead (Pb)	0.00090 lb/GWh	
	Manganese (Mn)	0.0040 lb/GWh	
	Nickel (Ni)	0.0040 lb/GWh	
	Selenium (Se)	0.030 lb/GWh	
	b. Hydrogen chloride (HCl)	0.30 lb per GWh	For Method 26A, collect a minimum

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . .	Using these requirements, as appropriate, (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
			of 4 dscm per run.
	OR	OR	
	Sulfur dioxide (SO2)(2M)	0.40 lb per MWh	SO2 CEMS.
	c. Mercury (Hg)	0.040 lb per GWh	Hg CEMS or Sorbent trap monitoring system.
3. IGCC unit	a. Particulate matter (PM)	0.050 lb per MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	0.000040 lb per MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP		Collect a minimum

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . .	Using these requirements, as appropriate, (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	metals:		of 4 dscm per run.
	Antimony (Sb)	0.000080 lb/GWh	
	Arsenic (As)	0.00020 lb/GWh	
	Beryllium (Be)	0.000030 lb/GWh	
	Cadmium (Cd)	0.00040 lb/GWh	
	Chromium (Cr)	0.020 lb/GWh	
	Cobalt (Co)	0.00080 lb/GWh	
	Lead (Pb)	0.00090 lb/GWh	
	Manganese (Mn)	0.0040 lb/GWh	
	Nickel (Ni)	0.0040 lb/GWh	
	Selenium (Se)	0.030 lb/GWh	

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate, (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	b. Hydrogen chloride (HCl)	0.30 lb per GWh	For Method 26A, collect a minimum of 4 dscm per run.
	OR		
	Sulfur dioxide (SO2)(3M)	0.40 lb per MWh	SO2 CEMS.
	c. Mercury (Hg)	0.000010 lb per GWh	Hg CEMS or Sorbent trap monitoring system.
4. Liquid oil-fired unit	a. Total HAP metals	0.00040 lb/MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP		Collect a minimum

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

If your EGU is in this subcategory	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate, (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	metals:		of 4 dscm per run.
	Antimony (Sb)	0.0020 lb/GWh	
	Arsenic (As)	0.0020 lb/GWh	
	Beryllium (Be)	0.00070 lb/GWh	
	Cadmium (Cd)	0.00040 lb/GWh	
	Chromium (Cr)	0.020 lb/GWh	
	Cobalt (Co)	0.0060 lb/GWh	
	Lead (Pb)	0.0060 lb/GWh	
	Manganese (Mn)	0.030 lb/GWh	
	Nickel (Ni)	0.040 lb/GWh	
	Selenium (Se)	0.0040 lb/GWh	

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

If your EGU is in this subcategory . .	For the following pollutants . .	You must meet the following emission limits and work practice standards . .	Using these requirements, as appropriate, (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	Mercury (Hg)	0.00010 lb/GWh	For Method 30B sample volume determination (8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.
	b. Hydrogen chloride (HCl)	0.00050 lb/MWh	For Method 26A, collect a minimum of 4 dscm per run.
	c. Hydrogen fluoride (HF)	0.00050 lb/MWh	For Method 26A, collect a minimum

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

If your EGU is in this subcategory	For the following pollutants . . .	You must meet the following emission limits and work practice standards . .	Using these requirements, as appropriate, (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
5. Solid oil-derived fuel-fired unit	a. Particulate matter (PM)	0.050 lb/MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	0.00020 lb/MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.00090 lb/GWh	
	Arsenic (As)	0.0020 lb/GWh	

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . .	Using these requirements, as appropriate, (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . .
	Beryllium (Be)	0.000080 lb/GWh	
	Cadmium (Cd)	0.0070 lb/GWh	
	Chromium (Cr)	0.0060 lb/GWh	
	Cobalt (Co)	0.0020 lb/GWh	
	Lead (Pb)	0.020 lb/GWh	
	Manganese (Mn)	0.0070 lb/GWh	
	Nickel (Ni)	0.0070 lb/GWh	
	Selenium (Se)	0.00090 lb/GWh	
	b. Hydrogen chloride (HCl)	0.00030 lb/MWh	For Method 26A, collect a minimum of 4 dscm per run.
	OR		

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate, (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	Sulfur dioxide (SO2)(4M)	0.40 lb/MWh	SO2 CEMS.
	c. Mercury (Hg)	0.0020 lb/GWh	Hg CEMS or Sorbent trap monitoring system.

As stated in § 63.9991, you must comply with the following applicable emission limits: <5>

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
1. Coal-fired unit designed for coal >/= 8,300 Btu/lb	a. Total particulate matter (PM)	0.030 lb/MMBtu or 0.30 lb/MWh	Collect a minimum of 2 dscm per run.
	OR Total non-Hg HAP metals	OR 0.000040 lb/MMBtu 0.00040 lb/MWh	Collect a minimum of 4 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.60 lb/TBtu or 0.0060 lb/GWh	
	Arsenic (As)	2.0 lb/TBtu or 0.020 lb/GWh	
	Beryllium (Be)	0.20 lb/TBtu or	

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

If your EGU is in this subcategory .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
		0.0020 lb/GWh	
	Cadmium (Cd)	0.30 lb/TBtu or 0.0030 lb/GWh	
	Chromium (Cr)	3.0 lb/TBtu or 0.030 lb/GWh	
	Cobalt (Co)	0.80 lb/TBtu or 0.0080 lb/GWh	
	Lead (Pb)	2.0 lb/TBtu or 0.020 lb/GWh	
	Manganese (Mn)	5.0 lb/TBtu or 0.050 lb/GWh	
	Nickel (Ni)	4.0 lb/TBtu or 0.040 lb/GWh	
	Selenium (Se)	6.0 lb/TBtu or 0.060 lb/GWh	
	b. Hydrogen	0.0020 lb per	For Method 26A,

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	chloride (HCl)	MMBtu or 0.020 lb per MWh	collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 60 liters per run.
	OR		
	Sulfur dioxide (SO2) fn6	0.20 lb per MMBtu or 2.0 lb per MWh	SO2 CEMS.
	c. Mercury (Hg)	1.0 lb/TBtu or 0.008 lb/GWh	LEE Testing for 28-30 days with 10 days maximum per run or Hg CEMS or Sorbent trap monitoring system.

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
2. Coal-fired unit designed for coal < 8,300 Btu/lb	a. Total particulate matter (PM)	0.030 lb/MMBtu or 0.30 lb/MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	0.000040 lb/MMBtu 0.00040 lb/MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.60 lb/TBtu or 0.0060 lb/GWh	
	Arsenic (As)	2.0 lb/TBtu or 0.020 lb/GWh	
	Beryllium (Be)	0.20 lb/TBtu or	

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
		0.0020 lb/GWh	
	Cadmium (Cd)	0.30 lb/TBtu or 0.0030 lb/GWh	
	Chromium (Cr)	3.0 lb/TBtu or 0.030 lb/GWh	
	Cobalt (Co)	0.80 lb/TBtu or 0.0080 lb/GWh	
	Lead (Pb)	2.0 lb/TBtu or 0.020 lb/GWh	
	Manganese (Mn)	5.0 lb/TBtu or 0.050 lb/GWh	
	Nickel (Ni)	4.0 lb/TBtu or 0.040 lb/GWh	
	Selenium (Se)	6.0 lb/TBtu or 0.060 lb/GWh	
	b. Hydrogen	0.0020 lb per	For Method 26A,

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

If your EGU is in this subcategory . . .	For the following pollutants . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	chloride (HCl)	MMBtu or 0.020 lb per MWh	collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 60 liters per run.
	OR		
	Sulfur dioxide (SO2) fn7	0.20 lb per MMBtu or 2.0 lb per MWh	SO2 CEMS.
	c. Mercury (Hg)	4.0 lb/TBtu or 0.040 lb/GWh	LEE Testing for 28-30 days with 10 days maximum per run or Hg CEMS or Sorbent trap monitoring system.

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
3. IGCC unit	a. Total particulate matter (PM)	0.050 lb/MMBtu or 0.30 lb/MWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0 lb/TBtu or 0.050 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.40 lb/TBtu or 0.0040 lb/GWh	
	Arsenic (As)	2.0 lb/TBtu or 0.020 lb/GWh	
	Beryllium (Be)	0.030 lb/TBtu or	

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . .
	Cadmium (Cd)	0.0030 lb/GWh 0.20 lb/TBtu or 0.0020 lb/GWh	
	Chromium (Cr)	3.0 lb/TBtu or 0.020 lb/GWh	
	Cobalt (Co)	2.0 lb/TBtu or 0.0040 lb/GWh	
	Lead (Pb)	0.0002 lb/MMBtu or 0.003 lb/MWh	
	Manganese (Mn)	3.0 lb/TBtu or 0.020 lb/GWh	
	Nickel (Ni)	5.0 lb/TBtu or 0.050 lb/GWh	
	Selenium (Se)	22.0 lb/TBtu or 0.20 lb/GWh	

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

If your EGU is in this subcategory	For the following pollutants . . .	You must meet the following emission limits and work practice standards . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . .
	b. Hydrogen chloride (HCl)	0.00050 lb/MMBtu or 0.0030 lb/MWh	For Method 26A, collect a minimum of 4 dscm per run.
	c. Mercury (Hg)	3.0 lb/TBtu or 0.020 lb/GWh	LEE Testing for 28-30 days with 10 days maximum per run or Hg CEMS or Sorbent trap monitoring system.
4. Liquid oil-fired unit	a. Total HAP metals OR Individual HAP	0.000030 lb/MMBtu or 0.00030 lb/MWh OR	Collect a minimum of 4 dscm per run. Collect a minimum

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Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	metals:		of 4 dscm per run.
	Antimony (Sb)	0.20 lb/TBtu or 0.0030 lb/GWh	
	Arsenic (As)	0.60 lb/TBtu or 0.0070 lb/GWh	
	Beryllium (Be)	0.060 lb/TBtu or 0.00070 lb/GWh	
	Cadmium (Cd)	0.10 lb/TBtu or 0.0020 lb/GWh	
	Chromium (Cr)	2.0 lb/TBtu or 0.020 lb/GWh	
	Cobalt (Co)	3.0 lb/TBtu or 0.020 lb/GWh	
	Lead (Pb)	2.0 lb/TBtu or	

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . .
	Manganese (Mn)	0.030 lb/GWh 5.0 lb/TBtu or	
	Nickel (Ni)	0.060 lb/GWh 8.0 lb/TBtu or	
	Selenium (Se)	0.080 lb/GWh 2.0 lb/TBtu or	
	Mercury (Hg)	0.020 lb/GWh 0.050 lb/TBtu or 0.00070 lb/GWh	For Method 29, collect a minimum of 4 dscm per run or for Method 30B sample volume determination (8.2.4), the estimated Hg concentration should nominally be < 1/2 the

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

If your EGU is in this subcategory	For the following pollutants . . .	You must meet the following emission limits and work practice standards . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	b. Hydrogen chloride (HCl)	0.00030 lb/MMBtu or 0.0030 lb/MWh	standard. For Method 26A, collect a minimum of 4 dscm per run.
	c. Hydrogen fluoride (HF)	0.00020 lb/MMBtu or 0.0020 lb/MWh	For Method 26A, collect a minimum of 4 dscm per run.
5. Solid oil-derived fuel-fired unit	a. Total particulate matter (PM)	0.20 lb/MMBtu or 2.0 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	0.000050 lb/MMBtu or 0.0010 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

If your EGU is in this subcategory . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . .
	Individual HAP metals:		Collect a minimum of 4 dscm per run.
	Antimony (Sb)	0.40 lb/TBtu or 0.0070 lb/GWh	
	Arsenic (As)	0.40 lb/TBtu or 0.0040 lb/GWh	
	Beryllium (Be)	0.070 lb/TBtu or 0.00070 lb/GWh	
	Cadmium (Cd)	0.40 lb/TBtu or 0.0040 lb/GWh	
	Chromium (Cr)	2.0 lb/TBtu or 0.020 lb/GWh	
	Cobalt (Co)	2.0 lb/TBtu or	

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

If your EGU is in this subcategory	For the following pollutants . . .	You must meet the following emission limits and work practice standards . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	Lead (Pb)	0.020 lb/GWh 11.0 lb/TBtu or	
	Manganese (Mn)	0.020 lb/GWh 3.0 lb/TBtu or	
	Nickel (Ni)	0.040 lb/GWh 9.0 lb/TBtu or	
	Selenium (Se)	0.090 lb/GWh 2.0 lb/TBtu	
	b. Hydrogen chloride (HCl)	0.0020 lb/GWh 0.0050 lb/MMBtu or 0.080 lb/GWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 60 liters per run.
	OR		

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . . .
	Sulfur dioxide (SO2) fn8	0.40 lb/MMBtu or 5.0 lb/MWh	SO2 CEMS.
	c. Mercury (Hg)	0.20 lb/TBtu or 0.0020 lb/GWh	LEE Testing for 28-30 days with 10 days maximum per run or Hg CEMS or Sorbent trap monitoring system.

fn5 footnote.

fn6 footnote.

fn7 footnote.

fn8 The alternate sulfur dioxide limit may not be used if your EGU does not have some form of flue gas desulfurization system installed.

As stated in § 63.9991, you must comply with the following applicable work practice standards:

Table 3 to Subpart UUUUU of Part 63—Work Practice Standards

If your EGU is . .	You must meet the following . .
1. An existing EGU	Conduct a performance test of the EGU annually as specified in § 63.10005.
2. A new EGU	Conduct a performance test of the EGU annually as specified in § 63.10005.

Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs

If you demonstrate compliance using .	You must meet these operating limits . .
1. Wet PM scrubber control	a. Maintain the pressure drop at or above the lowest 1-hour average pressure drop across the wet scrubber and the liquid flow rate at or above the lowest 1-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the PM emissions limitation.
2. Wet acid gas scrubbers	a. Maintain the pH at or above the lowest 1-hour average pressure drop

Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs

If you demonstrate compliance using . . .	You must meet these operating limits . . .
	across the wet scrubber and the liquid flow-rate at or above the lowest 1-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emissions limitation.
3. Fabric filter control	a. Install and operate a bag leak detection system according to § 63.10010 and operate the fabric filter such that the bag leak detection system does not initiate alarm mode more than 5 percent of the operating time during each 6-month period.
4. Electrostatic precipitator control	a. This option is only for EGUs that operate additional wet control systems. Maintain the secondary power input of the electrostatic precipitator at or above the lowest

Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs

If you demonstrate compliance using . . .	You must meet these operating limits . . .
	1-hour average secondary power measured during the most recent performance test demonstrating compliance with the PM emissions limitation.
5. Dry scrubber, DSI, or carbon injection control	Maintain the sorbent or carbon injection rate at or above the lowest 1-hour average sorbent flow rate measured during the most recent performance test demonstrating compliance with the Hg emissions limitation.
6. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rate calculated according to § 63.10011(d)(3), (4) and/or (5) is less than the applicable emission limits.
7. Performance testing	For EGUs that demonstrate compliance with a performance test, maintain the

Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs

If you demonstrate compliance using . . .	You must meet these operating limits . . .
	operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance test.
8. PM CEMS	Maintain the PM concentration (mg/dscm) at or below the highest 1-hour average measured during the most recent performance test demonstrating compliance with the total PM emissions limitation.

fn9. For emissions calculations involving periods of startup or shutdown, use procedures in § 63.10005(l).

As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:[9]

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .(10M)
1. Particulate matter (PM)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, Appendix A-1 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at 40 CFR part 60, Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.
		d. Measure the	Method 4 at 40 CFR

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .(10M)
		moisture content of the stack gas	part 60, Appendix A-3 of this chapter.
		e. Measure the PM emissions concentrations and determine the filterable and condensable fractions, as well as total PM	Method 202 at 40 CFR part 51, Appendix M of this chapter for condensable PM emissions from units and Method 5 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, Appendix A-3 or A-6 of this chapter for filterable PM emissions. Note

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .(10M)
			that the Method 5 front half temperature shall be 320 [degrees] F +/- 25 [degrees] F.
		f. Convert emissions concentration to lb per MMBtu emissions rates or lb/MWh emissions rates	Method 19 F-factor methodology at 40 CFR part 60, Appendix A-7 of this chapter, or calculate using mass emissions rate and electrical output data.
2. Total or	Emissions Testing	a. Select sampling	Method 1 at 40 CFR

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .(10M)
individual non-Hg HAP metals		ports location and the number of traverse points	part 60, Appendix A-1 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at 40 CFR part 60, Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.
		d. Measure the moisture content	Method 4 at 40 CFR part 60, Appendix

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . .	You must . .	Using . . .(10M)
		of the stack gas	A-3 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration	Method 29 at 40 CFR part 60, Appendix A-8 of this chapter. Determine total filterable HAP metals according to section 8.3.1.1 prior to beginning metals analyses.
		f. Convert	Method 19 F-factor

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .(10M)
		emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb per MMBtu or lb per MWh emissions rates	methodology at 40 CFR part 60, Appendix A-7 of this chapter, or calculate using mass emissions rate and electrical output data.
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, Appendix A-1 of this chapter.
		b. Determine velocity and	Method 2, 2F, or 2G at 40 CFR part

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . .	You must . . .	Using . . .(10M)
		volumetric flow-rate of the stack gas	60, Appendix A-2 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at 40 CFR part 60, Appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981.
		d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, Appendix A-3 of this chapter.
		e. Measure the HCl and HF emissions concentrations	Method 26 if there are no entrained water droplets in the exhaust stream

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .(10M)
			or 26A if there are entrained water droplets in the exhaust stream at 40 CFR part 60, Appendix A-8 of this chapter.
		f. Convert emissions concentration to lb per MMBtu or lb per MWh emissions rates	Method 19 F-factor methodology at 40 CFR part 60, Appendix A-7 of this chapter, or calculate using mass emissions rate and electrical output data.
	OR	OR	

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .(10M)
	HCl and/or HF CEMS	a. Install, operate, and maintain the CEMS	PS 15 or 6 at 40 CFR part 60, Appendix B of this chapter and QA Procedure 1 at 40 CFR part 60, Appendix F of this chapter.
		b. Install, operate, and maintain the diluents gas, flow rate, and/or moisture monitoring systems	Section 4.1.3 and 5.3 of Appendix A of this subpart.
		c. Convert hourly emissions concentrations to	Method 19 F-factor methodology at 40 CFR part 60,

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .(10M)
		30 boiler operating day rolling average lb per MMBtu emissions rates or lb/MWh emissions rates	Appendix A-7 of this chapter, or calculate using mass emissions rate and electrical output data.
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, Appendix A-1 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, Appendix A-1 or A-2 of this chapter.
		c. Determine	Method 3A or 3B at

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . .	Using . .(10M)
		oxygen and carbon dioxide concentrations of the stack gas	40 CFR part 60, Appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.
		d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, Appendix A-3 of this chapter.
		e. Measure the Hg emission concentration	Method 29 or 30B at 40 CFR part 60, Appendix A-8 of this chapter or ASTM Method D6784-02 (2008) as specified.
		f. Convert emissions	Section 6 of Appendix A of this

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .(10M)
		concentration to lb per TBtu emissions rates	subpart.
	OR	OR	
	Hg CEMS	a. Install, operate, and maintain the CEMS	Sections 3.2.1 and 5.1 of Appendix A of this subpart.
		b. Install, operate, and maintain the diluents gas, flow rate, and/or moisture monitoring systems	Section 4.1.3 and 5.3 of Appendix A of this subpart.
		c. Convert hourly emissions concentrations to 30 boiler	Section 6 of Appendix A of this subpart.

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . .	Using . . .	You must . . .	Using . . .(10M)
		operating day rolling average lb per MMBtu emissions rates or lb/MWh emissions rates	
	OR	OR	
	Sorbent trap monitoring system	a. Install, operate, and maintain the sorbent trap monitoring system	Sections 3.2.2 and 5.2 of Appendix A of this subpart.
		b. Install, operate, and maintain the diluents gas, flow rate, and/or moisture monitoring systems	Section 4.1.3 and 5.3 of Appendix A of this subpart.

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .(10M)
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb per MMBtu emissions rates or lb/MWh emissions rates	Section 6 of Appendix A of this subpart.
	OR LEE testing	OR a. Select sampling ports location and the number of traverse points	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at 40 CFR part 60, Appendix A-1 of this chapter.

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .(10M)
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, Appendix A-1 or A-2 of this chapter or flow monitoring systems certified by Section 4.1.3 and 5.3 of Appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at 40 CFR part 60, Appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981 or diluent gas

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .(10M)
			monitoring systems certified by Section 4.1.3 and 5.3 of Appendix A of this subpart.
		d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, Appendix A-3 of this chapter or moisture monitoring systems certified by Section 4.1.3 and 5.3 of Appendix A of this subpart.
		e. Measure the Hg emission concentration	Method 30B at 40 CFR part 60, Appendix A-8 of

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .(10M)
			this chapter.
		f. Convert emissions concentrations to 30 boiler operating day rolling average lb per MMBtu emissions rates or lb/MWh emissions rates	Section 6 of Appendix A of this subpart.
		g. Convert 30 boiler operating day rolling average lb per MMBtu pr lb/MWh to lb per year	Potential maximum annual heat input in MMBtu or potential maximum electricity generated in MWh.
5. Sulfur dioxide (SO2)	SO2 CEMS	a. Install, operate, and	PS 2 or 6 at 40 CFR part 60,

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .(10M)
		maintain the CEMS	Appendix B of this chapter and QA Procedure 1 at 40 CFR part 60, Appendix F of this chapter.
		b. Install, operate, and maintain the diluents gas, flow rate, and/or moisture monitoring systems	Section 4.1.3 and 5.3 of Appendix A of this subpart.
		c. Convert hourly emissions concentrations to 30 boiler	Method 19 F-factor methodology at 40 CFR part 60, Appendix A-7 of

Table 5 to Subpart UUUUU of Part 63—Performance Stack Testing Requirements

To conduct a performance test for the following pollutant . .	Using . . .	You must . . .	Using . . .(10M)
		operating day rolling average lb per MMBtu emissions rates or lb/MWh emissions rates	this chapter, or calculate using mass emissions rate and electrical output data.

n10 All ASTM, ANSI, and ASME methods are incorporated by reference.

n11 All ASTM, ANSI, and ASME methods are incorporated by reference.

As stated in § 63.10008, you must comply with the following requirements for fuel analysis testing for existing, new, or reconstructed affected sources. However, equivalent methods may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

Table 6 to Subpart UUUUU of Part 63—Fuel Analysis Requirements

To conduct a fuel analysis for the following pollutant . .	You must . .	Using . . .(11M)
1. Mercury (Hg)	a. Collect fuel samples	Procedure in § 63.10008(c) or ASTM D2234/D2234M (for coal) or equivalent.
	b. Composite fuel samples	Procedure in § 63.10008(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3020A (for liquid samples) or ASTM D2013/D2013M- (for coal) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 (for coal) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 or equivalent.
	f. Measure Hg concentration in fuel sample	ASTM D6722-01 (for coal) or SW-846-7471A (for solid samples) or SW-846-7470A (for liquid samples) or equivalent.

Table 6 to Subpart UUUUU of Part 63—Fuel Analysis Requirements

To conduct a fuel analysis for the following pollutant . .	You must . . .	Using . . .(11M)
	g. Convert concentration into units of pounds of pollutant per TBtu of heat content or lb per MWh	Method 19 F-factor methodology at 40 CFR part 60, Appendix A-7 of this chapter, or calculate using mass emissions rate and electrical output data.
2. Other non-Hg HAP metals	a. Collect fuel samples	Procedure in § 63.10008(c) or ASTM D2234/D2234M (for coal) or equivalent.
	b. Composite fuel samples	Procedure in § 63.10008(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3020A (for liquid samples) or ASTM D2013/D2013M- (for coal) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 (for coal) or equivalent.

Table 6 to Subpart UUUUU of Part 63—Fuel Analysis Requirements

To conduct a fuel analysis for the following pollutant . .	You must . .	Using . . .(11M)
	e. Determine moisture content of the fuel type	ASTM D3173 or equivalent.
	f. Measure other non-Hg HAP metals concentrations in fuel sample	EPA SW-846-6010B or ASTM D3683 (for coal samples) or equivalent; EPA SW-846-6010B (for other solid fuel samples) or equivalent; or EPA SW-846-6020 (for liquid fuel samples) or equivalent.
	g. Convert concentration into units of pounds of pollutant per TBtu of heat content or lb per MWh	Method 19 F-factor methodology at 40 CFR part 60, Appendix A-7 of this chapter, or calculate using mass emissions rate and electrical output data.
	b. Composite fuel samples	Procedure in § 63.10008(d) or

Table 6 to Subpart UUUUU of Part 63—Fuel Analysis Requirements

To conduct a fuel analysis for the following pollutant . .	You must . . .	Using . . .(11M)
		equivalent.
3. Hydrogen chloride (HCl)	a. Collect fuel samples	Procedure in § 63.10008(c) or D2234/D2234M (for coal) or equivalent.
	b. Composite fuel samples	Procedure in § 63.10008(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3020A (for liquid samples), EPA SW-846-3050B (for solid samples), or ASTM D2013/D2013M (for coal) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 (for coal) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 or equivalent.
	f. Measure chlorine concentration in fuel sample	EPA SW-846-9250 or ASTM D6721 (for coal) or equivalent, or EPA

Table 6 to Subpart UUUUU of Part 63—Fuel Analysis Requirements

To conduct a fuel analysis for the following pollutant . .	You must . . .	Using . . .(11M)
		SW-846-9250 or ASTM E776 (for solid or liquid samples) or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content or lb per MWh	Method 19 F-factor methodology at 40 CFR part 60, Appendix A-7 of this chapter, or calculate using mass emissions rate and electrical output data.
4. Hydrogen fluoride (HF)	a. Collect fuel samples	Procedure in § 63.10008(c) or D2234/D2234M (for coal) or equivalent.
	b. Composite fuel samples	Procedure in § 63.10008(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3020A (for liquid samples), EPA SW-846-3050B (for solid

Table 6 to Subpart UUUUU of Part 63—Fuel Analysis Requirements

To conduct a fuel analysis for the following pollutant . .	You must . . .	Using . . .(11M)
		samples), or ASTM D2013/D2013M (for coal) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 (for coal) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 or equivalent.
	f. Measure chlorine concentration in fuel sample	EPA SW-846-9250 or ASTM D6721 (for coal) or equivalent, or EPA SW-846-9250 or ASTM E776 (for solid or liquid samples) or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content	Method 19 F-factor methodology at 40 CFR part 60, Appendix A-7 of this chapter.

As stated in § 63.10007, you must comply with the following requirements for establishing operating limits:

Table 7 to Subpart UUUUU of Part 63—Establishing Operating Limits

If you have an applicable emission limit for . .	And your operating limits are based on . .	You must . .	Using . . .	According to the following requirements
1. Particulate matter (PM), mercury (Hg), or other non-Hg HAP metals	a. Wet scrubber operating parameters	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.10011(c)	(1) Data from the pressure drop and liquid flow rate monitors and the PM, Hg, or other non-Hg HAP metals performance test	(a) You must collect pressure drop and liquid flow-rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average hourly pressure drops and liquid

Table 7 to Subpart UUUUU of Part 63—Establishing Operating Limits

If you have an applicable emission limit for . .	And your operating limits are based on . .	You must . .	Using . . .	According to the following requirements
				flow rates for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
	b. Electrostatic precipitator operating parameters	i. Establish a site-specific secondary power input according to	(1) Data from the secondary power input during the PM, Hg, or other	(a) You must collect secondary voltage and current and

Table 7 to Subpart UUUUU of Part 63—Establishing Operating Limits

If you have an applicable emission limit for . . .	And your operating limits are based on . .	You must . .	Using . .	According to the following requirements
	(option only for units that operate wet scrubbers)	§ 63.10011(c)	non-Hg HAP metals performance test	calculate total ESP secondary power input data every 15 minutes during the entire period of the performance tests; (b) Determine the average hourly total secondary power inputs for each individual test run in the three-run

Table 7 to Subpart UUUUU of Part 63—Establishing Operating Limits

If you have an applicable emission limit for . .	And your operating limits are based on . .	You must . .	Using . . .	According to the following requirements
				performance test by computing the average of all the 15-minute readings taken during each test run.
	c. Filterable PM results obtained from performance testing and are measured continuously using PM CEMS	i. Establish a site-specific filterable PM concentration according to § 63.10011(d)	(1) Data from the PM performance test	(a) You must collect at least 3 test runs of Method 5 filterable PM results.
2. Hydrogen	a. Wet	i. Establish a	(1) Data from	(a) You must

Table 7 to Subpart UUUUU of Part 63—Establishing Operating Limits

If you have an applicable emission limit for . .	And your operating limits are based on . .	You must . .	Using . . .	According to the following requirements
chloride (HCl) or hydrogen fluoride (HF)	scrubber operating parameters	site-specific minimum pH and flow rate operating limits according to § 63.10011(c)	the pH and liquid flow rate monitors and the HCl performance test	collect pH and liquid flow rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average hourly pH liquid flow rates for each individual test run in the three-run performance test by

Table 7 to Subpart UUUUU of Part 63—Establishing Operating Limits

If you have an applicable emission limit for . . .	And your operating limits are based on . .	You must . .	Using . . .	According to the following requirements
				computing the average of all the 15-minute readings taken during each test run.
	b. Dry scrubber or DSI operating parameters	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.10011(c). If different acid gas	(1) Data from the sorbent injection rate monitors and HCl or Hg performance test	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average

Table 7 to Subpart UUUUU of Part 63—Establishing Operating Limits

If you have an applicable emission limit for . . .	And your operating limits are based on . .	You must . .	Using . . .	According to the following requirements
		sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent		hourly sorbent injection rates of the three test run averages measured during the performance test.

As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following:

Table 8 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
1. Fabric filter bag leak detection operation	Installing and operating a bag leak detection system according to § 63.10010 and operating the fabric filter such that the requirements in § 63.10021(a)(9) are met.
2. Wet PM scrubber pressure drop and liquid flow-rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.10010 and 63.10020; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.10011(c).
3. Wet acid gas scrubber pH and liquid flow rate	a. Collecting the pH and liquid flow rate monitoring system data according to §§ 63.10010 and 63.10020; and

Table 8 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
	b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average pH and liquid flow-rate at or above the operating limits established during the performance test according to § 63.10011(c).
4. Dry scrubber or DSI sorbent or carbon injection rate	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber or DSI according to §§ 63.10010 and 63.10020; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average sorbent or carbon injection rate at or above the operating limit established during the performance test according to § 63.10011(c).

Table 8 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
5. Electrostatic precipitator secondary power input	a. Collecting the secondary power input monitoring system data for the electrostatic precipitator according to §§ 63.10010 and 63.10020; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average secondary power input at or above the operating limits established during the performance test according to § 63.10011(c).
6. Fuel pollutant content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.10011(c) or (d) as applicable; and b. Keeping monthly records of fuel use according to § 63.10021(a).
7. Filterable PM as measured by PM	a. Collecting the PM concentration

Table 8 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
CEMS	data using a PM CEMS installed, operated and maintained in accordance with PS 11 at 40 CFR part 60, Appendix B of this chapter and QA Procedure 5 at 40 CFR part 60, Appendix F of this chapter; b. Converting hourly emissions concentrations to 30 boiler operating mg/dscm values; and c. Maintaining the 30 boiler operating day rolling average mg/dscm values below the operating limits established during the performance test according to § 63.10011(d).

As stated in § 63.10031, you must comply with the following requirements for reports:

Table 9 to Subpart UUUUU of Part 63—Reporting Requirements

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.10031(c)(1) through (11) through (11); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting	Semiannually according to the requirements in § 63.10031(b).

Table 9 to Subpart UUUUU of Part 63—Reporting Requirements

You must submit a(n)	The report must contain . . .	You must submit the report . . .
	period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the	

Table 9 to Subpart UUUUU of Part 63—Reporting Requirements

You must submit a(n)	The report must contain .	You must submit the report . . .
	report must contain the information in § 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.10031(e); and d. If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown,	

Table 9 to Subpart UUUUU of Part 63—Reporting Requirements

You must submit a(n)	The report must contain . . .	You must submit the report . . .
	and malfunction plan, the compliance report must include the information in § 63.10(d)(5)(i)	
2. An immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the emission standard	a. Actions taken for the event; and	i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and
	b. The information in § 63.10(d)(5)(ii)	ii. By letter within 7 working days after the end of the event unless

Table 9 to Subpart UUUUU of Part 63—Reporting Requirements

You must submit a(n)	The report must contain .	You must submit the report . . .
		you have made alternative arrangements with the permitting authority.

As stated in § 63.10040, you must comply with the applicable General Provisions according to the following:

Table 10 to Subpart UUUUU of Part 63—Applicability of General Provisions to Subpart UUUUU

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	Yes.
§ 63.6(a), (b)(1)-(b)(5), (b)(7), (c), (f)(2)-(3), (g),	Compliance with Standards and Maintenance Requirements	Yes.

Table 10 to Subpart UUUUU of Part 63—Applicability of General Provisions to Subpart UUUUU

Citation	Subject	Applies to subpart UUUUU
(h)(2)-(h)(9), (i), (j)		
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.10000(b) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.7(a), (b), (c),	Performance Testing	Yes.
(d), (e)(2)-(e)(9), (f), (g), and (h)	Requirements	
§ 63.7(e)(1)	Performance testing	No. See § 63.10007.
§ 63.8	Monitoring Requirements	
63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.

Table 10 to Subpart UUUUU of Part 63—Applicability of General Provisions to Subpart UUUUU

Citation	Subject	Applies to subpart UUUUU
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1), (c), (d)(1)-(2), (e), and (f)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii)-(ix)	Other CMS requirements	Yes.
§ 63.10(b)(3), and		No.

Table 10 to Subpart UUUUU of Part 63—Applicability of General Provisions to Subpart UUUUU

Citation	Subject	Applies to subpart UUUUU
(d)(3)-(5)		
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions	Yes.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See 63.10031(h) and (i) for malfunction reporting requirements.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and	Yes.

Table 10 to Subpart UUUUU of Part 63—Applicability of General Provisions to Subpart UUUUU

Citation	Subject	Applies to subpart UUUUU
§ 63.13-63.16	Delegation Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§ 63.1(a)(5), (a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9)	Reserved	No.

Appendix A to Subpart UUUUU—Hg Monitoring Provisions

1. General Provisions

1.1 *Applicability.* These monitoring provisions apply to the measurement of total vapor phase mercury (Hg) in emissions from electric utility steam generating units, using either a mercury continuous emission monitoring system (Hg CEMS) or a sorbent trap monitoring system. The Hg CEMS or sorbent trap monitoring system must be capable of measuring the total vapor phase mercury in units of the applicable emissions standard (e.g., lb/TBtu or lb/GWh), regardless of speciation. The monitoring, recordkeeping, and

reporting provisions of this appendix shall be considered to be met to the extent that they have already been, and are continuing to be, met or exceeded under another Federal or State program.

1.2 *Initial Certification and Recertification Procedures.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall comply with the initial certification and recertification procedures in section 4 of this appendix.

1.3 *Quality Assurance and Quality Control Requirements.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall meet the applicable quality assurance requirements in section 5 of this appendix.

1.4 *Missing Data Procedures.* The owner or operator of an affected unit is not required to substitute for missing data from Hg CEMS or sorbent trap monitoring systems. Any process operating hour for which the CEMS fails to produce quality-assured Hg mass emissions data is counted as an hour of monitoring system downtime.

2. Monitoring of Hg Emissions for Various Configurations

2.1 *Single Unit-Single Stack Configuration.* For an affected unit that exhausts to the atmosphere through a single, dedicated stack, the owner or operator shall install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system and any other necessary monitoring components needed to express

the measured Hg emissions in the units of the applicable emissions standard, in accordance with section 3.2 of this appendix.

2.2 *Unit Utilizing Common Stack with Other Affected Unit(s).* When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, the owner or operator shall either:

2.2.1 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section in the duct to the common stack from each unit; or

2.2.2 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section in the common stack.

2.3 *Unit Utilizing Common Stack with Non-affected Units.* When one or more affected units shares a common stack with one or more non-affected units, the owner or operator shall either:

2.3.1 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section in the duct to the common stack from each affected unit; or

2.3.2 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section in the common stack and attribute all of the Hg emissions measured at the common stack to the affected unit(s).

2.4 *Unit with a Main Stack and a Bypass Stack.* If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, the owner and operator shall either:

2.4.1 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section on both the main stack and the bypass stack; or

2.4.2 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section only on the main stack, and report the maximum potential Hg concentration (as defined in section 3.2.1.4.1 of this appendix) for each unit operating hour in which the bypass stack is used.

2.5 *Unit with Multiple Stack or Duct Configuration.* If the flue gases from an affected unit either: are discharged to the atmosphere through more than one stack; or are fed into a single stack through two or more ducts and the owner or operator chooses to monitor in the ducts rather than in the stack, the owner or operator shall either:

2.5.1 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section in each of the multiple stacks; or

2.5.2 Install, certify, maintain, and operate the monitoring systems described in paragraph 2.1 of this section in each of the ducts that feed into the stack.

3. Mercury Emissions Measurement Methods

The following definitions, equipment specifications, procedures, and performance criteria are applicable to the measurement of vapor-phase Hg emissions from electric utility steam generating units, under relatively low-dust conditions (i.e., sampling in the stack or duct after all pollution control devices). The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents

the sum of elemental Hg (Hg<0>, CAS Number 7439-97-6) and oxidized forms of Hg.

3.1 *Definitions.*

3.1.1 *Mercury Continuous Emission Monitoring System or Hg CEMS* means all of the equipment used to continuously determine the total vapor phase Hg concentration. The measurement system may include the following major subsystems: Sample acquisition, Hg<+2> to Hg<0> converter, sample transport, sample conditioning, flow control/gas manifold, gas analyzer, and data acquisition and handling system (DAHS).

3.1.2 *Sorbent Trap Monitoring System* means the equipment required to monitor Hg emissions continuously, using paired sorbent traps containing iodated charcoal (IC) or other suitable sorbent medium. The monitoring system consists of a probe, paired sorbent traps, an umbilical line, moisture removal components, an airtight sample pump, a gas flow meter, and an automated data acquisition and handling system. The system samples the stack gas at a rate proportional to the stack gas volumetric flow rate. The sampling is a batch process. The average Hg concentration in the stack gas for the sampling period is determined, in units of micrograms per dry standard cubic meter ([mu]g/dscm), based on the sample volume measured by the gas flow meter and the mass of Hg collected in the sorbent traps.

3.1.3 *NIST* means the National Institute of Standards and Technology, located in Gaithersburg, Maryland.

3.1.4 *NIST-traceable elemental Hg standards* means either: compressed gas cylinders having known concentrations of elemental Hg, which have been

prepared according to the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards"; or calibration gases having known concentrations of elemental Hg, produced by a generator that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators", or an interim version of that protocol.

3.1.5 *NIST-traceable source of oxidized Hg* means a generator that is capable of providing known concentrations of vapor phase mercuric chloride (HgCl[2]), and that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators", or an interim version of that protocol.

3.1.6 Calibration Gas means a NIST-traceable gas standard containing known concentration of a gaseous species that is produced and certified in accordance with an EPA traceability protocol.

3.1.7 *Span value* means a conservatively high estimate of the gas concentrations or stack gas flow rates to be measured by a CEMS. For a Hg pollutant concentration monitor, the span value should be set to approximately twice the concentration corresponding to the emission standard, rounded off as appropriate.

3.1.8 *Zero-Level Gas* means calibration gas with a concentration that is below the level detectable by a gas monitoring system.

3.1.9 *Low-Level Gas* means calibration gas with a concentration that is 20 to 30 percent of the span value.

3.1.10 *Mid-Level Gas* means calibration gas with a concentration that is 50 to 60 percent of the span value.

3.1.11 *High-Level Gas* means calibration gas with a concentration that is 80 to 100 percent of the span value.

3.1.12 *Calibration Error Test* means a test designed either to assess the ability of a gas monitor to measure the concentrations of calibration gases accurately, or the ability of a flow monitor to read electronic reference signals accurately. A zero-level gas (or signal) and an upscale gas (or signal) are required for this test. For gas monitors, either a mid-level gas or a high-level gas may be used. For a flow monitor, an upscale signal of 50 to 70 percent of the calibration span value is required. For a Hg CEMS, the upscale gas may either be an elemental or oxidized Hg standard.

3.1.13 *Linearity Check* means a test designed to determine whether the response of a gas analyzer is linear across its measurement range. Three calibration gas standards (i.e., low, mid, and high-level gases) are required for this test. For a Hg CEMS, elemental Hg calibration standards are required.

3.1.14 *System Integrity Check* means a test designed to assess the transport and measurement of oxidized Hg by a Hg CEMS. Oxidized Hg standards are used for this test. For a three-level system integrity check, low, mid, and high-level calibration gases are required. For a single-level check, either a mid-level gas or a high-level gas may be used.

3.1.15 *Cycle Time Test* means a test designed to measure the amount of time it takes for a gas monitor, while operating normally, to respond to a known step

change in gas concentration. For this test, a zero gas and a high-level gas are required. For a Hg CEMS, the high-level gas may be either an elemental or an oxidized Hg standard.

3.1.16 *Relative Accuracy Test Audit or RATA* means a series of nine or more test runs, directly comparing readings from a CEMS or sorbent trap monitoring system to measurements made with a reference stack test method. The relative accuracy (RA) of the monitoring system is expressed as the absolute mean difference between the monitoring system and reference method measurements plus the absolute value of the 2.5 percent error confidence coefficient, divided by the mean value of the reference method measurements.

3.1.17 *Unit Operating Hour* means a clock hour in which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.1.18 *Stack Operating Hour* means a clock hour in which gases flow through a particular monitored stack or duct (either for part of the hour or for the entire hour), while the associated unit(s) are combusting fuel.

3.1.19 *Unit Operating Day* means a calendar day in which a unit combusts any fuel.

3.1.20 *QA Operating Quarter* means a calendar quarter in which there are at least 168 unit or stack operating hours (as defined in this section).

3.1.21 *Grace Period* means a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

3.2 *Continuous Monitoring Methods.*

3.2.1 *Hg CEMS.* A typical Hg CEMS is shown in Figure A-1. The CEMS in Figure A-1 is a dilution extractive system, which measures Hg concentration on a wet basis, and is the most commonly-used type of Hg CEMS. Other system designs may be used, provided that the CEMS meets the performance specifications in section 4.1.1 of this appendix.

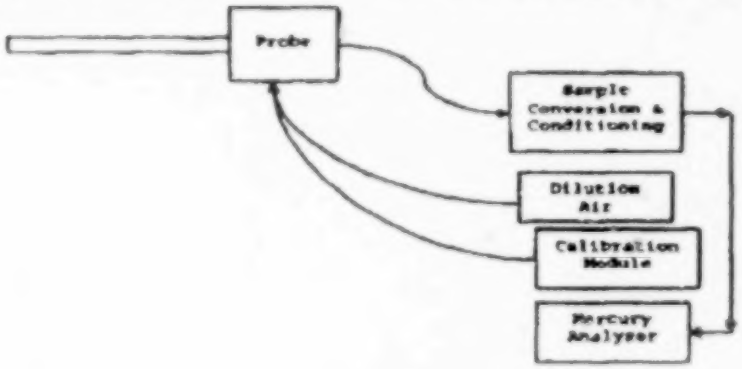

FIGURE A-1. TYPICAL MERCURY CEMS

3.2.1.1 *Equipment Specifications.*

3.2.1.1.1 *Materials of Construction.* All wetted sampling system components, including probe components prior to the point at which the calibration gas is introduced, must be chemically inert to all Hg species. Materials such as perfluoroalkoxy (PFA) Teflon<TM>, quartz, treated stainless steel (SS) are examples of such materials.

3.2.1.1.2 *Temperature Considerations.* All system components prior to the Hg<+2> to Hg<0> converter must be maintained at a sample temperature above the acid gas dew point.

3.2.1.1.3 *Measurement System Components.*

3.2.1.1.3.1 Sample Probe. The probe must be made of the appropriate materials as noted in paragraph

3.2.1.1.1 of this section, heated when necessary, as described in paragraph 3.2.1.1.3.4 of this section, and configured with ports for introduction of calibration gases.

3.2.1.1.3.2 *Filter or Other Particulate Removal Device.* The filter or other particulate removal device is part of the measurement system, must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section, and must be included in all system tests.

3.2.1.1.3.3 *Sample Line.* The sample line that connects the probe to the converter, conditioning system, and analyzer must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section.

3.2.1.1.3.4 *Conditioning Equipment.* For wet basis systems, such as the one shown in Figure A-1, the sample must be kept above its dew point either by: Heating the sample line and all sample transport components up to the inlet of the analyzer (and, for hot-wet extractive systems, also heating the analyzer); or diluting the sample prior to analysis using a dilution probe system. The components required for these operations are considered to be conditioning equipment. For dry basis measurements, a condenser, dryer or other suitable device is required to remove moisture continuously from the sample gas, and any equipment needed to heat the probe or sample line to avoid condensation prior to the moisture removal component is also required.

3.2.1.1.3.5 *Sampling Pump.* A pump is needed to push or pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. If a mechanical sample

pump is used and its surfaces are in contact with the sample gas prior to detection, the pump must be leak free and must be constructed of a material that is non-reactive to the gas being sampled (see paragraph 3.2.1.1.1 of this section). For dilution-type measurement systems, such as the system shown in Figure A-1, an ejector pump (eductor) may be used to create a sufficient vacuum that sample gas will be drawn through a critical orifice at a constant rate. The ejector pump may be constructed of any material that is non-reactive to the gas being sampled.

3.2.1.1.3.6 *Calibration Gas System(s).* Design and equip each Hg monitor to permit the introduction of known concentrations of elemental Hg and HgCl[2] separately, at a point preceding the sample extraction filtration system, such that the entire measurement system can be checked. The calibration gas system(s) must be designed so that the flow rate exceeds the sampling system flow requirements and that the gas is delivered to the CEMS at atmospheric pressure.

3.2.1.1.3.7 *Sample Gas Delivery.* The sample line may feed directly to a converter, to a by-pass valve (for Hg speciating systems), or to a sample manifold. All valve and/or manifold components must be made of material that is non-reactive to the gas sampled and the calibration gas, and must be configured to safely discharge any excess gas.

3.2.1.1.3.8 *Hg Analyzer.* An instrument is required that continuously measures the total vapor phase Hg concentration in the gas stream. The analyzer may also be capable of measuring elemental and oxidized Hg separately.

3.2.1.1.3.9 *Data Recorder.* A recorder, such as a computerized data acquisition and handling system

(DAHS), digital recorder, or data logger, is required for recording measurement data.

3.2.1.2 *Reagents and Standards.*

3.2.1.2.1 *NIST Traceability.* Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this section) shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg<0> and HgCl[2] are required. Special reagents and equipment may be needed to prepare the Hg<0> and HgCl[2] gas standards (e.g., NIST-traceable solutions of HgCl[2] and gas generators equipped with mass flow controllers).

3.2.1.2.2 *Required Calibration Gas Concentrations.*

3.2.1.2.2.1 *Zero-Level Gas.* A zero-level calibration gas with a Hg concentration below the detectable limit of the analyzer is required for calibration error tests and cycle time tests of the CEMS.

3.2.1.2.2.2 *Low-Level Gas.* A low-level calibration gas with a Hg concentration of 20 to 30 percent of the span value is required for linearity checks and 3-level system integrity checks of the CEMS. Elemental Hg standards are required for the linearity checks and oxidized Hg standards are required for the system integrity checks.

3.2.1.2.2.3 *Mid-Level Gas.* A mid-level calibration gas with a Hg concentration of 50 to 60 percent of the span value is required for linearity checks and for 3-level system integrity checks of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are

required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error tests.

3.2.1.2.2.4 *High-Level Gas.* A high-level calibration gas with a Hg concentration of 80 to 100 percent of the span value is required for linearity checks, 3-level system integrity checks, and cycle time tests of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error and cycle time tests.

3.2.1.3 *Installation and Measurement Location.* For the Hg CEMS and any additional monitoring system(s) needed to convert Hg concentrations to the desired units of measure (i.e., a flow monitor, CO[2] or O[2] monitor, and/or moisture monitor, as applicable), install each monitoring system at a location: That represents the emissions exiting to the atmosphere; and at which it is likely that the CEMS can pass the relative accuracy test.

3.2.1.4 *Monitor Span and Range Requirements.* Determine the appropriate span and range value(s) for the Hg CEMS as described in paragraphs 3.2.1.4.1 through 3.2.1.4.3 of this section.

3.2.1.4.1 *Maximum Potential Concentration.* There are three options for determining the maximum potential Hg concentration (MPC). Option 1 applies to coal combustion. You may use a default value of 10 [mu]g/scm for all coal ranks (including coal refuse) except for lignite; for lignite, use 16 [mu]g/scm. Option

2 is to base the MPC on the results of site-specific Hg emission testing. This option may be used only if the unit does not have add-on Hg emission controls or a flue gas desulfurization system, or if testing is performed upstream of all emission control devices. If Option 2 is selected, perform at least three test runs at the normal operating load, and the highest Hg concentration obtained in any of the tests shall be the MPC. If different coals are blended as part of normal operation, use the highest MPC for any fuel in the blend. Option 3 is to use fuel sampling and analysis to estimate the MPC. To make this estimate, use the average Hg content (i.e., the weight percentage) from at least three representative fuel samples, together with other available information, including, but not limited to the maximum fuel feed rate, the heating value of the fuel, and an appropriate F-factor. Assume that all of the Hg in the fuel is emitted to the atmosphere as vapor-phase Hg.

3.2.1.4.2 *Span Value.* To determine the span value of the Hg CEMS, multiply the Hg concentration corresponding to the applicable emissions standard by two. If the result of this calculation is an exact multiple of 10 [mu]g/scm, use the result as the span value. Otherwise, round off the result to the next highest integer. Alternatively, you may round off the span value to the next highest multiple of 10 [mu]g/scm.

3.2.1.4.3 *Full-Scale Range.* The full-scale range of the Hg analyzer output must include the MPC.

3.2.2 *Sorbent Trap Monitoring System.* A sorbent trap monitoring system (as defined in paragraph 3.1.2 of this section) may be used as an alternative to a Hg CEMS. If this option is selected, the monitoring system shall be installed, maintained, and operated in

accordance with Performance Specification 12B in Appendix B to part 60 of this chapter. The system shall be certified in accordance with the provisions of section 4.1.2 of this appendix.

3.2.3 *Other Necessary Monitoring Systems.* When the applicable Hg emission limit is specified in units of lb/TBtu or lb/GWh, some or all of the monitoring systems described in paragraphs 3.2.3.1 and 3.2.3.2 of this section will be needed to convert the measured Hg concentrations to the units of the emissions standard. These additional monitoring systems shall be installed, certified, maintained, operated, and quality-assured according to the applicable provisions of this appendix (see section 4.1.3 of this appendix). The calculation methods for the types of emission limits described in paragraphs 3.2.3.1 and 3.2.3.2 of this section are presented in section 6.2 of this appendix.

3.2.3.1 *Heat Input-Based Emission Limits.* For a heat input-based Hg emission limit (e.g., in lb/TBtu), data from a certified CO[2] or O[2] monitor are needed, along with a fuel-specific F-factor and a conversion constant to convert measured Hg concentration values to the units of the standard. In some cases, the stack gas moisture content must also be accounted for, as follows:

3.2.3.1.1 Determine the stack gas moisture content using a certified continuous moisture monitoring system; or

3.2.3.1.2 Use the moisture value determined during the most recent Hg emissions test while combusting the fuel type currently in use; or

3.2.3.1.3 For coal combustion, use a fuel-specific moisture default value. For anthracite coal, use 3.0% H[2] O; for bituminous coal, use 6.0% H[2] O; for sub-

bituminous coal, use 8.0% H[2] O; and for lignite, use 11.0% H[2] O.

3.2.3.2 *Electrical Output-Based Emission Rates.* If the applicable Hg limit is electrical output-based (e.g., lb/GWh), hourly electrical load data and unit operating times are required in addition to hourly data from a certified flow rate monitor and (if applicable) moisture data.

3.2.3.3 *Span and Range of Flow Rate, Diluent Gas, and Moisture Monitors.* Set the span value of a CO[2] or O[2] monitor at 1.00 to 1.25 times the maximum potential concentration. Set the span value of a flow rate monitor at 1.00 to 1.25 times the maximum potential flow rate, in units of standard cubic feet per hour (scfh). If the units of measure for daily calibrations of the flow monitor are not expressed in scfh, convert the calculated span value from scfh to an equivalent "calibration span value" in the units of measure actually used for daily calibrations. Set the full-scale range of the CO[2,] O[2], and flow monitors such that the majority of the data will fall between 20 and 80% of full-scale. For a continuous moisture sensor, there is no span value requirement; set up and operate the instrument according to the manufacturer's instructions.

4. Certification and Recertification Requirements

4.1 *Certification Requirements.* All Hg CEMS and sorbent trap systems and the monitoring systems used to continuously measure Hg emissions in units of the applicable emissions standard in accordance with this appendix must be certified prior to the applicable compliance date specified in § 63.9984.

4.1.1 *Hg CEMS.* Table A-1, below, summarizes the certification test requirements and performance specifications for a Hg CEMS. The CEMS may not be used to report quality-assured data until these performance criteria are met. Paragraphs 4.1.1.1 through 4.1.1.5 of this section provide specific instructions for the required tests.

4.1.1.1 *7-Day Calibration Error Test.* Perform the 7-day calibration error test on 7 consecutive operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in sections 3.1.8, 3.1.10, and 3.1.11 of this appendix). Either elemental or oxidized NIST-traceable Hg standards (as defined in sections 3.1.4 and 3.1.5 of this appendix) may be used for the test. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate each monitor in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over nonconsecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the monitor (i.e., resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined, and use only the unadjusted analyzer

responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A-1. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A-1.

Table A-1—Required Certification Tests and Performance Specifications for Hg CEMS

For this required certification test . . .	The main performance specification fn1 is . .	The alternate performance specification fn1 is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test fn2	:R-A: </=5.0% of span value, for both the zero and upscale gases, on each of the 7 days	:R-A: </= 1.0 [mu]g/scm	The alternate specification may be used on any day of the test.
Linearity check fn3	:R-A[avg]: </= 10,0% of the reference gas concentration at each calibration gas level	:R-A[avg]: </= 0.8[mu]g/scm	The alternate specification may be used at any gas level.
3-level system	:R-A[avg]: </=	:R-A[avg]: </=	The alternate

Table A-1—Required Certification Tests and Performance Specifications for Hg CEMS

For this required certification test . . .	The main performance specification fn1 is . . .	The alternate performance specification fn1 is . .	And the conditions of the alternate specification are . . .
integrity check fn4	10.0% of the reference gas concentration at each calibration gas level	0.8[mu]g/scm	specification may be used at any gas level.
RATA	20.0% RA	:RM[avg]-C[avg]: </=1.0 [mu]g/scm **	RM[avg] < 5.0 [mu]g/scm.
Cycle time test fn2	15 minutes. fn5		

fn1 Note that :R-A: is the absolute value of the difference between the reference gas value and the analyzer reading. :R-A[avg]: is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.

fn2 Use either elemental or oxidized Hg standards.

fn3 Use elemental Hg standards.

fn4 Use oxidized Hg standards. Not required if the CEMS does not have a converter.

fn5 Stability criteria-Readings change by < 2.0% of span or by </= 0.5 [mu]g/m fn3, for 2 minutes.

** Note that :RM[avg]-C[avg]: is the absolute difference between the mean reference method value and the mean CEMS value from the RATA. The arithmetic difference between RM[avg] and C[avg] can be either + or -.

4.1.1.2 *Linearity Check.* Perform the linearity check using low, mid, and high-level concentrations of NIST-traceable elemental Hg standards. Three gas injections at each concentration level are required, with no two successive injections at the same concentration level. Introduce the calibration gas at the gas injection port, as specified in section 3.2.1.1.3.6 of this appendix. Operate each monitor at its normal operating temperature and conditions. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Record the monitor response from the data acquisition and handling system for each gas injection. At each concentration level, use the average analyzer response to calculate the linearity error (LE), as described in Table A-1. The LE must either meet the main performance specification or the alternative specification in Table A-1.

4.1.1.3 *Three-Level System Integrity Check.* Perform the 3-level system integrity check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as described in Table A-1. The SIE must either meet the main performance specification or the alternative specification in Table

A-2. (**Note:** This test is not required if the CEMS does not have a converter).

4.1.1.4 *Cycle Time Test.* Perform the cycle time test, using a zero-level gas and a high-level calibration gas. Either an elemental or oxidized NIST-traceable Hg standard may be used as the high-level gas. Perform the test in two stages—upscale and downscale. The slower of the upscale and downscale response times is the cycle time for the CEMS. Begin each stage of the test by injecting calibration gas after achieving a stable reading of the stack emissions. The cycle time is the amount of time it takes for the analyzer to register a reading that is 95 percent of the way between the stable stack emissions reading and the final, stable reading of the calibration gas concentration. Use the following criterion to determine when a stable reading of stack emissions or calibration gas has been attained—the reading is stable if it changes by no more than 2.0 percent of the span value or 0.5 [mu]g/scm (whichever is less restrictive) for two minutes.

4.1.1.5 *Relative Accuracy Test Audit (RATA).* Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784-02 (the Ontario Hydro Method) and Methods 29, 30A, and 30B in appendix A-8 to part 60 of this chapter. When Method 29 or the Ontario Hydro Method is used, paired sampling trains are required. To validate a Method 29 or Ontario Hydro test run, calculate the relative deviation (RD) using Equation A-1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 [mu]g/dscm. If the average concentration is </= 1.0 [mu]g/dscm, the RD must not exceed 20

percent. The RD results are also acceptable if the absolute difference between the two Hg concentrations does not exceed 0.03 [mu]g/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

$$RD = \frac{|C_a - C_b|}{C_a + C_b} \times 100 \qquad \text{(Eq. A-1)}$$

Where:

RD = Relative deviation between the Hg concentrations of samples "a" and "b" (percent)

C[a] = Hg concentration of Hg sample "a" ([mu]g/dscm)

C[b] = Hg concentration of Hg sample "b" ([mu]g/dscm)

4.1.1.5.1 *Special Considerations. Special Considerations.* A minimum of nine valid test runs must be performed, directly comparing the CEMS measurements to the reference method. If 12 or more runs are performed, you may discard the results from a maximum of three runs for calculating relative accuracy. The minimum time per run is 21 minutes if Method 30A is used. If the Ontario Hydro Method, Method 29, or Method 30B is used, the time per run must be long enough to collect a sufficient mass of Hg to analyze. Complete the RATA within 168 unit operating hours, except when the Ontario Hydro Method or Method 29 is used, in which case up to 336 operating hours may be taken to finish the test.

4.1.1.5.2 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the monitoring system, on a [mu]g/scm basis, as described in section 12 of Performance Specification 2 or 6 in Appendix B to part 60 of this chapter. The CEMS must either meet the

main performance specification or the alternative specification in Table A-1.

4.1.1.5.3 *Bias Adjustment.* Measurement or adjustment of Hg CEMS data for bias is not required.

4.1.2 *Sorbent Trap Monitoring Systems.* For the initial certification of a sorbent trap monitoring system, only a RATA is required.

4.1.2.1 *Reference Methods.* The acceptable reference methods for the RATA of a sorbent trap system are listed in paragraph 4.1.1.5 of this section.

4.1.2.2 *Special Considerations.* The special considerations specified in paragraph 4.1.1.5.1 of this section apply to the RATA of a sorbent trap monitoring system. During the RATA, the monitoring system must be operated and quality-assured in accordance with Performance Specification 12B in Appendix B to part 60 of this chapter. The type of sorbent material used by the traps during the RATA must be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

4.1.2.3 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the Hg concentration monitoring system, on a [mu]g/scm basis, as described in section 12 of Performance Specification 2 or 6 in appendix B to part 60 of this chapter. The main and alternative RATA performance specifications in Table A-1 for Hg CEMS also apply to the sorbent trap monitoring system.

4.1.2.4 *Bias Adjustment.* Measurement or adjustment of sorbent trap monitoring system data for bias is not required.

4.1.3 *Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems.* Monitoring systems that are used to measure stack gas volumetric flow rate and/or diluent gas concentration and/or stack gas moisture content in order to convert Hg concentration data to units of the applicable emission limit must be certified. The minimum certification test requirements and performance specifications for these systems are shown in Table A-2, below.

4.2 *Recertification.* Whenever the owner or operator makes a replacement, modification, or change to a certified Hg CEMS, sorbent trap monitoring system, flow rate monitoring system, diluent gas monitoring system, or moisture monitoring system that may significantly affect the ability of the system to accurately measure or record the Hg concentration, stack gas volumetric flow rate, CO[2] concentration, O[2] concentration, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the flow or concentration profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

Table A-2—Minimum Required Certification Tests and Performance Specifications for Other Monitoring Systems

For this required certification test . . .	Of this auxiliary monitoring system . .	The main performance specification fn1 is . . .	The alternate performance specification fn2 is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test	O[2] or CO[2]	:R - A: </= 0.5% O[2] or CO[2] for both the zero and upscale gases, on each day of the test		
7-day calibration error test	Flow rate	:R-A: </=3.0% of calibration span value for both the zero and upscale signals, on each day of the test	:R-A: </=0.01 in. H[2]O, for DP-type monitors	The alternate specification may be used on any day of the tests.
Linearity check	O[2] or CO[2]	:R-A[avg]: </= 5.0% of	:R-A: </=0.5% O[2] or	The alternate specification

Table A-2—Minimum Required Certification Tests and Performance Specifications for Other Monitoring Systems

For this required certification test . . .	Of this auxiliary monitoring system . .	The main performance specification fn1 is . .	The alternate performance specification fn2 is . . .	And the conditions of the alternate specification are . . .
		the reference gas value	CO[2]	may be used at any gas level.
Cycle time test	O[2] or CO[2]	</= 15 minutes.		
RATA	O[2] or CO[2]	10.0% RA	:RM[avg]-C[avg]: </= 1.0% O[2] or % CO[2]	
RATA	Flow rate	10.0% RA.		
RATA	Moisture	10.0% RA	:RM[avg] - C[avg]: </= 1.5% H[2]O	

fn1 Note that :R-A: is the absolute value of the difference between the reference gas value and the analyzer reading. :R-A[avg]: is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.

fn2 Note that :RM[avg]-C[avg]: is the absolute difference between the mean reference method value and the mean CEMS value from the RATA. The arithmetic difference between RM[avg] and C[avg] can be either + or -.

5. Ongoing Quality Assurance (QA) and Data Validation

5.1 *Hg CEMS.*

5.1.1 *Required QA Tests.* Periodic QA testing of each Hg CEMS is required following initial certification. The required QA tests, the test frequencies, and the performance specifications that must be met are summarized in Table A-3, below.

5.1.2 *Test Frequency.* The frequency for the required QA tests of the Hg CEMS shall be as follows:

5.1.2.1 Perform calibration error tests of the Hg CEMS daily. Use either NIST-traceable elemental Hg standards or NIST-traceable oxidized Hg standards for these calibrations. A zero-level gas and either a mid-level or high-level gas are required for these calibrations.

5.1.2.2 Perform a linearity check of the Hg CEMS in each QA operating quarter, using low-level, mid-level, and high-level NIST-traceable elemental Hg standards. For units that operate infrequently, limited exemptions from this test are allowed for "non-QA operating quarters" A maximum of three consecutive exemptions for this reason are permitted, following the quarter of the last test. After the third consecutive exemption, a linearity check must be performed in the next calendar quarter or within a grace period of 168 unit or stack operating hours after the end of that quarter. The test frequency for 3-level system integrity checks (if performed in lieu of linearity checks) is the same as for the linearity checks. Use low-level, mid-level, and high-level NIST-traceable oxidized Hg standards for the system integrity checks.

Table A-3—On-Going QA Test Requirements for Hg CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Calibration error test	Daily	Use either a mid- or high-level gas . Use either elemental or oxidized Hg . Calibrations are not required when the unit is not in operation	:R-A: </=5.0% of span value, or :R-A: </=1.0 [mu]g/scm.
Single-level system integrity check	Weekly fn1	. Required only for systems with converters . Use oxidized Hg—either mid- or high-level . Not required if	:R-A[avg]: </= 10.0% of the reference gas value; or :R-A[avg]: </= 0.8 [mu]g/scm.

Table A-3—On-Going QA Test Requirements for Hg CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
		daily calibrations are done with a NIST-traceable source of oxidized Hg	
Linearity check or 3-level system integrity check	Quarterly fn3	. Required in each "QA operating quarter" fn2 —and no less than once every 4 calendar quarters	:R-A[avg]: </= 10.0% of the reference gas value, at each calibration gas level, or :R-A[avg]: </= 0.8 [mu]g/scm.
		. 168 operating hour grace period available Use elemental Hg for linearity check	
		. Use oxidized Hg	

Table A-3—On-Going QA Test Requirements for Hg CEMS

Perform this type of QA test . . .	At this frequency . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
		for system integrity check . For system integrity check, CEMS must have a converter	
RATA	Annual fn4	Test deadline may be extended for "non-QA operating quarters," up to a maximum of 8 quarters from the quarter of the previous test 720 operating hour grace period available	20.0% RA; or :RM[avg] C[avg]: </= 1.0 [mu]g/scm; if RM[avg] < 5.0 [mu]g/scm.

fn1 "Weekly" means once every 168 unit operating hours.

fn2 A "QA operating quarter" is a calendar quarter with at least 168 unit or stack operating hours.

fn3 "Quarterly" means once every QA operating quarter.

fn4 "Annual" means once every four QA operating quarters.

5.1.2.3 A weekly single-level system integrity check (if required—see third column in Table A-3).

5.1.2.4 The test frequency for the RATAs of the Hg CEMS shall be annual, i.e., once every four QA operating quarters. For units that operate infrequently, extensions of RATA deadlines are allowed for non-QA operating quarters. Following a RATA, if there is a subsequent non-QA quarter, it extends the deadline for the next test by one calendar quarter. However, there is a limit to these extensions—the deadline may not be extended beyond the end of the eighth calendar quarter after the quarter of the last test. At that point, a RATA must either be performed within the eighth calendar quarter or in a 720 hour unit or stac operating hour grace period following that quarter.

5.1.3 *Data Validation.* The Hg CEMS is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any of the acceptance criteria for the required QA tests in Table A-3 is not met. The CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed.

5.1.4 *Grace Periods.*

5.1.4.*1 A 168* unit or stack operating hour grace period is available for quarterly linearity checks and 3-level system integrity checks of the Hg CEMS.

5.1.4.*2 A 720* unit or stack operating hour grace period is available for RATAs of the Hg CEMS.

5.1.4.3 There is no grace period for weekly system integrity checks. The test must be completed once every 168 unit or stack operating hours.

5.1.5 *Adjustment of Span.* If the Hg concentration readings exceed the span value for a significant percentage of the unit operating hours in a calendar quarter, make any necessary adjustments to the MPC and span value. A diagnostic linearity check is required within 168 unit or stack operating hours after changing the span value.

5.2 *Sorbent Trap Monitoring Systems.*

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification 12B (PS 12B) in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B-1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.2.2 For ongoing QA, periodic RATAs of the system are required.

5.2.2.1 The RATA frequency shall be annual, i.e., once every four QA operating quarters.

5.2.2.2 The same RATA performance criteria specified in Table A-3 for Hg CEMS shall apply to the annual RATAs of the sorbent trap monitoring system.

5.2.2.*3 A 720* unit or stack operating hour grace period is available for RATAs of the monitoring system.

5.2.2.4 Data validation for RATAs of the system shall be done in accordance with paragraph 5.1.3 of this section.

5.3 *Flow Rate, Diluent Gas, and Moisture Monitoring Systems.* The minimum on-going QA test requirements for these monitoring systems are summarized in Table A-4, below. The data validation provisions in paragraph 5.1.3 apply to these systems. The linearity grace period described in paragraph 5.1.4.1 applies to the O[2] and CO[2] monitors. The RATA grace period in paragraph 5.1.4.2 of this section applies to the O[2,] CO[2], moisture, and flow rate monitors.

5.4 *QA/QC Program for Continuous Monitoring Systems.* The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for all continuous monitoring systems that are used to provide data under this subpart (i.e., all Hg CEMS, sorbent trap monitoring systems, and any associated monitoring systems used to convert Hg concentration data to the appropriate units of measure). At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. RM100

Table A-4—Minimum On-Going Quality Assurance Test Requirements for Auxiliary Monitoring Systems

Perform this QA test . . .	For this monitoring system . . .	At this frequency . .	With these conditions and exceptions . .	The acceptance criteria are . . .
Calibration error test	O[2] or CO[2]	Daily	Use either a mid or high level gas . Not required on non-operating days	:R-A: </= 1.0% O[2] or CO[2].
Calibration error test	Flow rate	Daily	. Not required on non-operating days	:R-A: </= 6.0% of calibration span value or :R-A: </= 0.02 in. H[2]O for a DP-type monitor.
Interference check	Flow rate	Daily	. Not required on non-operating days	Must be passed.
Linearity check	O[2] or CO[2]	Quarterly	. Required in each QA	:R-A: </= 5.0% of

Table A-4—Minimum On-Going Quality Assurance Test Requirements for Auxiliary Monitoring Systems

Perform this QA test . . .	For this monitoring system . . .	At this frequency	With these conditions and exceptions . .	The acceptance criteria are . . .
			operating quarter—but no less than once every 4 calendar quarters 168 operating hour grace period available	reference gas or :R-A: </= 1.0% O[2] or CO[2].
Leak check	Flow rate	Quarterly	. Required only for DP-type flow monitors	Must be passed.
RATA	O[2] or CO[2]	Annual ***	. Once every four QA operating quarters, not to exceed 8 calendar quarters	RA </= 7.5%; or :RM[avg] - C[avg]: </= 0.7% O[2] or CO[2]. RA </= 7.5%.

Table A-4—Minimum On-Going Quality Assurance Test Requirements for Auxiliary Monitoring Systems

Perform this QA test . . .	For this monitoring system . . .	At this frequency . .	With these conditions and exceptions . .	The acceptance criteria are .
RATA	Flow rate	Annual ***	Once every four QA operating quarters, not to exceed 8 calendar quarters	
RATA	Moisture	Annual ***	Once every four QA operating quarters, not to exceed 8 calendar quarters	RA </= 7.5%; or :RM[avg] - C[avg]: </= 1.0% H[2]O.

*** Note that these RATAs can still be passed at RA percentages up to and including 10.0% RA. Alternate specifications of :R-A: </= 1.0% O[2] or CO[2] and :R-A: </= 1.5% H[2]O are also acceptable. However, for all of these acceptance criteria, the test frequency becomes semiannual (i.e., once every two QA operating quarters) monitors. The RATA grace period in paragraph 5.1.4.2 of this section applies to the O[2,] CO[2], and flow rate monitors.

5.4.1 *General Requirements.*

5.4.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the monitoring system in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

5.4.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

5.4.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any monitoring system in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded (e.g., changing of flow monitor polynomial coefficients or K factors, changing the dilution ratio of a gas monitor, etc.), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

5.4.2 *Specific Requirements for Hg CEMS, Flow Rate, Diluent Gas, and Moisture Monitoring Systems.*

5.4.2.1 *Daily Calibrations, Linearity Checks and System Integrity Checks.* Keep a written record of the

procedures used for daily calibrations of the Hg CEMS and all associated monitoring systems. If moisture and/or chlorine is added to the Hg calibration gas, explain how the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration is accounted for. Also keep records of the procedures used to perform linearity checks (of the Hg CEMS and, if applicable, the CO[2] or O[2] monitor) and the procedures for system integrity checks of the Hg CEMS. Explain how the test results are calculated and evaluated.

5.4.2.2 *Monitoring System Adjustments.* Explain how each component of the continuous emission monitoring system will be adjusted to provide correct responses to calibration gases or reference signals after routine maintenance, repairs, or corrective actions.

5.4.2.3 *Relative Accuracy Test Audits.* Keep a written record of procedures used for RATAs of the monitoring systems. Indicate the reference methods used and explain how the test results are calculated and evaluated.

5.4.3 *Specific Requirements for Sorbent Trap Monitoring Systems.*

5.4.3.1 *Sorbent Trap Identification and Tracking.* Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for tracking purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg collection period.

5.4.3.2 *Monitoring System Integrity and Data Quality.* Explain the procedures used to perform the leak checks when a sorbent trap is placed in service

and removed from service. Also explain the other QA procedures used to ensure system integrity and data quality, including, but not limited to, gas flow meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in Table 12B-1 in section 9.0 of Performance Specification 12B in Appendix B to part 60 of this chapter. All reference meters used to calibrate the gas flow meters (e.g., wet test meters) shall be periodically recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST-traceable calibration device is used as a reference flow meter, the QA plan must include a protocol for ongoing maintenance and periodic recalibration to maintain the accuracy and NIST-traceability of the calibrator.

5.4.3.3 *Hg Analysis.* Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps. Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 11.0 of Performance Specification 12B in Appendix B to part 60 of this chapter.

5.4.3.4 *Data Collection Period.* State, and provide the rationale for, the minimum acceptable data collection period (e.g., one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Include in the discussion such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.4.3.5 *Relative Accuracy Test Audit Procedures.* Keep records of the procedures and details peculiar to

the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

6. Data Reduction and Calculations

6.1 *Data Reduction.*

6.1.1 Reduce the data from Hg CEMS and (as applicable) flow rate, diluent gas, and moisture monitoring systems to hourly averages, in accordance with § 60.13(h)(2) of this chapter.

6.1.2 For sorbent trap monitoring systems, determine the Hg concentration for each data collection period and assign this concentration value to each operating hour in the data collection period.

6.1.3 For any operating hour in which valid data are not obtained, either for Hg concentration or for a parameter used in the emissions calculations (i.e., flow rate, diluent gas concentration, or moisture, as applicable), do not calculate the Hg emission rate for that hour.

6.1.4 Operating hours in which valid data are not obtained, either for Hg concentration or for another parameter, are considered to be hours of monitor downtime.

6.2 *Calculation of Hg Emission Rates.* Use the applicable calculation methods in paragraphs 6.2.1 and 6.2.2 of this section to convert Hg concentration values to the appropriate units of the emission standard.

6.2.1 *Heat Input-Based Hg Emission Rates.* Calculate hourly heat input-based Hg emission rates, in units of lb/TBtu, according to sections 6.2.1.1 through 6.2.1.4 of this appendix.

6.2.1.1 Select an appropriate emission rate equation from among Equations 19-1 through 19-9 in EPA Method 19 in appendix A-7 to part 60 of this chapter.

6.2.1.2 Calculate the Hg emission rate in lb/MMBtu, using the equation selected from Method 19. Multiply the Hg concentration value by 6.24 x 10<-11> to convert it from [mu]g/scm to lb/scf.

6.2.1.3 Multiply the lb/MMBtu value obtained in section 6.2.1.2 of this appendix by 10<6> to convert it to lb/TBtu.

6.2.1.4 If the heat input-based Hg emission rate limit must be met over a specified averaging period (e.g., a 30 boiler operating day rolling average), use Equation 19-19 in EPA Method 19 to calculate the Hg emission rate for each averaging period. Do not include non-operating hours with zero emissions in the average.

6.2.2 *Electrical Output-Based Hg Emission Rates.* Calculate electrical output-based Hg emission limits in units of lb/GWh, according to sections 6.2.2.1 through 6.2.2.3 of this appendix.

6.2.2.1 First, calculate the Hg mass emissions for each operating hour in which valid data are obtained for all parameters, using Equation A-2 of this section (for wet-basis measurements of Hg concentration) or Equation A-3 of this section (for dry-basis measurements), as applicable:

$$M_h = K C_h Q_h t_h \qquad \text{(Equation A-2)}$$

Where:

M[h] = Hg mass emissions for the hour (lb)

K = Units conversion constant, 6.236 x 10<-11> lb-scm/[mu]g-scf

C[h] = Hourly average Hg concentration, wet basis ([mu]g/scm)

Q[h] = Stack gas volumetric flow rate for the hour (scfh). (**Note:** Use unadjusted flow rate values; bias adjustment is not required)

t[h] = Unit or stack operating time, fraction of the clock hour, expressed as a decimal. For example, t[h] = 1.00 for a full operating hour, 0.50 for 30 minutes of operation, 0.00 for a non-operating hour, etc.) *or*

$$M_h = K C_h Q_h t_h (1 - B_{ws}) \qquad \text{(Equation A-3)}$$

Where:

M[h] = Hg mass emissions for the hour (lb)

K = Units conversion constant, 6.236 x 10<-11> lb-scm/[mu]g-scf

C[h] = Hourly average Hg concentration, dry basis ([mu]g/dscm)

Q[h] = Stack gas volumetric flow rate for the hour (scfh). (*Note:* Use unadjusted flow rate values; bias adjustment is not required)

t[h] = Unit or stack operating time, fraction of the clock hour, expressed as a decimal. For example, t[h] = 1.00 for a full operating hour, 0.50 for 30 minutes of operation, 0.00 for a non-operating hour, etc.)

B[ws] = Moisture fraction of the stack gas, expressed as a decimal (equal to %H[2] O/100)

6.2.2.2 Next, use Equation A-4 of this section to calculate the emission rate for each unit or stack operating hour in which valid data are obtained for all parameters.

$$E_{ho} = \frac{M_h}{(MW)_h (t_h)} x\, 10^3 \qquad \text{(Equation A-4)}$$

Where:

E[ho] = Electrical output-based Hg emission rate (lb/GWh)

M[h] = Hg mass emissions for the hour, from Equation A-2 or A-3 of this section, as applicable (lb)

(MW)[h] = Electrical load for the hour, in megawatts (MW)

t[h] = Unit or stack operating time, fraction of the hour, expressed as a decimal. For example, t[h] = 1.00 for a full operating hour, 0.50 for 30 minutes of operation, etc.)

10<3> = Conversion factor from megawatts to gigawatts

6.2.2.3 If the electrical output-based Hg emission rate limit must be met over a specified averaging period (e.g., a 30 boiler operating day rolling average), use Equation A-5 of this section to calculate the Hg emission rate for each averaging period.

$$\overline{E}_o = \frac{\sum_{h=1}^{n} E_{ho}}{n} \qquad \text{(Equation A-5)}$$

Where:

E[o] = Hg emission rate for the averaging period (lb/GWh)

E[ho] = Electrical output-based hourly Hg emission rate for unit or stack operating hour "h" in the averaging period, from Equation A-4 of this section (lb/GWh)

n = Number of unit or stack operating hours in the averaging period in which valid data were obtained for

all parameters. (*Note:* Do *not* include non-operating hours with zero emission rates in the average).

7. Recordkeeping and Reporting

7.1 *Recordkeeping Provisions.* The owner or operator shall, for each affected unit and each non-affected unit under section 2.3 of this appendix, maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record. The file shall contain the information in paragraphs 7.1.1 through 7.1.10 of this section.

7.1.1 *Monitoring Plan Records.* The owner or operator of an affected unit shall prepare and maintain a monitoring plan for each affected unit or group of units monitored at a common stack and each non-affected unit under section 2.3 of this appendix. The monitoring plan shall contain sufficient information on the continuous monitoring systems that provide data under this subpart, and how the data derived from these systems are sufficient to demonstrate that all Hg emissions from the unit or stack are monitored and reported.

7.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (*e.g.*, a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

7.1.1.2 *Contents of the Monitoring Plan.* For the Hg CEMS, sorbent trap monitoring systems, and any flow

rate and/or moisture, and/or diluent gas monitors used to provide data under this subpart, the monitoring plan shall contain the following information, as applicable:

7.1.1.2.1 *Electronic.* Unit or stack IDs; monitoring location(s); type(s) of fuel combusted; type(s) of emission controls; maximum rated unit heat input(s); megawatt rating(s); monitoring methodologies used; monitoring system information (unique system and component ID numbers, parameters monitored); formulas used to calculate emissions and heat input; unit operating ranges and normal load level(s); monitor span and range information.

7.1.1.2.2 *Hard Copy.* Schematics and/or blueprints showing the location of monitoring systems and test ports; data flow diagrams; test protocols; monitor span and range calculations; miscellaneous technical justifications.

7.1.2 *Operating Parameter Records. T* he owner or operator shall record the following information for each operating hour of each affected unit and each non-affected unit under section 2.3 of this appendix, and also for each group of units utilizing a common stack, to the extent that these data are needed to convert Hg concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 7.1.2.1 and 7.1.2.2 of this section:

7.1.2.1 The date and hour;

7.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

7.1.2.3 The hourly gross unit load (rounded to nearest MWge);

7.1.2.4 The hourly heat input rate (MMBtu/hr, rounded to the nearest tenth);

7.1.2.5 An identification code for the formula used to calculate the hourly heat input rate, as provided in the monitoring plan; and

7.1.2.6 The F-factor used for the heat input rate calculation.

7.1.3 *Hg Emissions Records (Hg CEMS).* For each affected unit or common stack using a Hg CEMS, the owner or operator shall record the following information for each unit or stack operating hour:

7.1.3.1 The date and hour;

7.1.3.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the CEMS provides a quality-assured value of Hg concentration for the hour;

7.1.3.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour ([mu]g/scm, rounded to the nearest tenth);

7.1.3.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour; and

7.1.3.5 Monitor availability, as a percentage of unit or stack operating hours.

7.1.4 *Hg Emissions Records (Sorbent Trap Monitoring Systems).* For each affected unit or common stack using a sorbent trap monitoring system, each owner or operator shall record the following information for the unit or stack operating hour in each data collection period:

7.1.4.1 The date and hour;

7.1.4.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the sorbent trap system provides a quality-assured value of Hg concentration for the hour;

7.1.4.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour ([mu]g/scm, rounded to the nearest tenth). Note that when a quality-assured Hg concentration value is obtained for a particular data collection period, that single concentration value is applied to each operating hour of the data collection period.

7.1.4.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour;

7.1.4.5 The average flow rate of stack gas through each sorbent trap (in appropriate units, e.g., liters/min, cc/min, dscm/min);

7.1.4.6 The gas flow meter reading (in dscm, rounded to the nearest hundredth), at the beginning and end of the collection period and at least once in each unit operating hour during the collection period;

7.1.4.7 The ratio of the stack gas flow rate to the sample flow rate, as described in section 12.2 of Performance Specification 12B in Appendix B to part 60 of this chapter; and

7.1.4.8 Data availability, as a percentage of unit or stack operating hours.

7.1.5 *Stack Gas Volumetric Flow Rate Records.*

7.1.5.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required for routine operation of sorbent trap monitoring systems,

to maintain the required ratio of stack gas flow rate to sample flow rate (see section 8.2.2 of Performance Specification 12B in Appendix B to part 60 of this chapter). Stack gas flow rate data are also needed in order to demonstrate compliance with heat input-based and electrical output-based Hg emissions limits, as provided in sections 6.2.1 and 6.2.2 of this appendix.

7.1.5.2 For each affected unit or common stack, if measurements of stack gas flow rate are required, use a certified flow rate monitor to record the following information for each unit or stack operating hour:

7.1.5.2.1 The date and hour;

7.1.5.2.2 Monitoring system and component identification codes, as provided in the monitoring plan, if a quality-assured flow rate value is obtained for the hour;

7.1.5.2.3 The hourly average volumetric flow rate, if a quality-assured flow rate value is obtained for the hour (in scfh, rounded to the nearest thousand);

7.1.5.2.4 A special code, indicating whether or not a quality-assured flow rate value is obtained for the hour; and

7.1.5.2.5 Monitor availability, as a percentage of unit or stack operating hours.

7.1.6 *Records of Stack Gas Moisture Content.*

7.1.6.1 Correction of Hg concentration data for moisture is sometimes required, when compliance with an applicable Hg emissions limit must be demonstrated, as provided in sections 6.2.1 and 6.2.2 of this appendix. In particular, these corrections are required for sorbent trap monitoring systems and for Hg CEMS that measure Hg concentration on a dry basis.

7.1.6.2 If moisture corrections are required, use a certified moisture monitoring system to record the following information for each unit or stack operating hour (except where a default moisture value is used; in that case, keep a record of the default value currently in use):

7.1.6.2.1 The date and hour;

7.1.6.2.2 Monitoring system and component identification codes for the system, as provided in the monitoring plan, if a quality-assured moisture value is obtained for the hour;

7.1.6.2.3 Hourly average moisture content of the flue gas (percent H[2] O, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the wet- and dry-basis oxygen hourly averages (in percent O[2], rounded to the nearest tenth);

7.1.6.2.4 A special code, indicating whether or not a quality-assured moisture value is obtained for the hour; and

7.1.6.2.5 Monitor availability, as a percentage of unit or stack operating hours.

7.1.7 *Records of Diluent Gas (CO* [2] *or O* [2]*) Concentration.*

7.1.7.1 When a heat input-based Hg mass emissions limit must be met (e.g., in units of lb/TBtu), hourly measurements of CO[2] or O[2] concentration are required, in order to calculate hourly heat input values.

7.1.7.2 For each affected unit or common stack, if measurements of diluent gas concentration are required, use a certified CO[2] or O[2] monitor to

record the following information for each unit or stack operating hour:

7.1.7.2.1 The date and hour;

7.1.7.2.2 Monitoring system and component identification codes, as provided in the monitoring plan, if a quality-assured O[2] or CO[2] concentration is obtained for the hour;

7.1.7.2.3 The hourly average O[2] or CO[2] concentration (in percent, rounded to the nearest tenth);

7.1.8.2.4 A special code, indicating whether or not a quality-assured O[2] or CO[2] concentration value is obtained for the hour; and

7.1.7.2.5 Monitor availability, as a percentage of unit or stack operating hours.

7.1.8 *Hg Mass Emissions Records.* When compliance with a Hg emission limit in units of lb/GWh is required, Hg mass emissions must be calculated. In such cases, record the following information for each operating hour of affected unit or common stack:

7.1.8.1 The date and hour;

7.1.8.2 The calculated hourly Hg mass emissions, from Equation A-2 or A-3 in section 6.2.2 of this appendix (lb, rounded to three decimal places), if valid values of Hg concentration, stack gas volumetric flow rate, and (if applicable) moisture data are all obtained for the hour;

7.1.8.3 An identification code for the formula (either Equation A-2 or A-3 in section 6.2.2 of this appendix) used to calculate hourly Hg mass emissions from Hg concentration, flow rate and (if applicable) moisture data; and

7.1.8.4 A code indicating that the Hg mass emissions were not calculated for the hour, if valid data for Hg concentration, flow rate, and/or moisture (as applicable) are not obtained for the hour.

7.1.9 *Hg Emission Rate Records.* For applicable Hg emission limits in units of lb/TBtu or lb/GWh, record the following information for each affected unit or common stack:

7.1.9.1 The date and hour;

7.1.9.2 The hourly Hg emissions rate (lb/TBtu or lb/GWh, as applicable, rounded to three decimal places), if valid values of Hg concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

7.1.9.3 An identification code for the formula (either the selected equation from Method 19 in section 6.2.1 of this appendix or Equation A-4 in section 6.2.2 of this appendix) used to derive the hourly Hg emission rate from Hg concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

7.1.9.4 A code indicating that the Hg emission rate was not calculated for the hour, if valid data for Hg concentration and/or any of the other necessary parameters are not obtained for the hour.

7.1.10 *Certification and Quality Assurance Test Records.* For the continuous monitoring systems used to provide data under this subpart at each affected unit (or group of units monitored at a common stack) and each non-affected unit under section 2.3 of this

appendix, record the following certification and quality-assurance information:

7.1.10.1 The reference values, monitor responses, and calculated calibration error (CE) values, for all required 7-day calibration error tests and daily calibration error tests of all volumetric flow rate monitors and gas monitors, including Hg CEMS;

7.1.10.2 The results (pass/fail) of the required daily interference checks of flow monitors;

7.1.10.3 The reference values, monitor responses, and calculated linearity error (LE) or system integrity error (SIE) values for all required linearity checks of all gas monitors, including Hg CEMS, and for all single-level and 3-level system integrity checks of Hg CEMS;

7.1.10.4 The results (pass/fail) of all required quarterly leak checks of all differential pressure-type flow monitors (if applicable);

7.1.10.5 The CEMS and reference method readings for each test run and the calculated relative accuracy results for all RATAs of all Hg CEMS, sorbent trap monitoring systems, and (as applicable) flow rate, diluent gas, and moisture monitoring systems;

7.1.10.6 The stable stack gas and calibration gas readings and the calculated results for the upscale and downscale stages of all required cycle time tests of all gas monitors, including Hg CEMS;

7.1.10.7 Supporting information for all required RATAs of volumetric flow rate monitoring systems, diluent gas monitoring systems, and moisture monitoring systems, including the raw field data and, as applicable, the results of reference method bias and drift checks, calibration gas certificates, the results of

lab analyses, and records of sampling equipment calibrations. For the RATAs of Hg CEMS and sorbent trap monitoring systems, keep sufficient records of the test dates, the raw reference method and monitoring system data, and the results of sample analyses to substantiate the reported test results; and

7.1.10.8 For sorbent trap monitoring systems, the results of all analyses of the sorbent traps used for routine daily operation of the system, and information documenting the results of all leak checks and the other applicable quality control procedures described in Table 12B-1 of Performance Specification 12B in Appendix B to part 60 of this chapter.

7.2 *Reporting Requirements.*

7.2.1 *General Reporting Provisions.* The owner or operator shall comply with the following reporting requirements for each affected unit (or group of units monitored at a common stack) and each non-affected unit under section 2.3 of this appendix:

7.2.1.1 Notifications, in accordance with paragraph 7.2.2 of this section;

7.2.1.2 Monitoring plan reporting, in accordance with paragraph 7.2.3 of this section;

7.2.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 7.2.4 of this section; and

7.2.1.4 Electronic quarterly report submittals, in accordance with paragraph 7.2.5 of this section.

7.2.2 *Notifications.* In addition to the notifications required elsewhere in this subpart, the owner or operator of any affected unit shall provide the following notifications for each affected unit (or group of units monitored at a common stack) and each non-

affected unit under section 2.3 of this appendix. Provide each notification at least 21 days prior to the event:

7.2.2.1 The date(s) of the required annual RATAs of the Hg CEMS, sorbent trap monitoring systems, and (as applicable) flow rate, diluent gas, and moisture monitoring systems used to provide data under this subpart;

7.2.2.2 The date on which emissions first exhaust through a new stack or flue gas desulfurization system; and

7.2.2.3 The date on which an affected unit is removed from service and placed into long-term cold storage, and the date on which the unit is expected to resume operation.

7.2.3 *Monitoring Plan Reporting.* The owner or operator of any affected unit shall make electronic and hard copy monitoring plan submittals for each affected unit (or group of units monitored at a common stack) and each non-affected unit under section 2.3 of this appendix, as follows:

7.2.3.1 At least 21 days prior to the initial certification testing or recertification testing of a monitoring system used to provide data under this subpart; and

7.2.3.2 Whenever an update of the monitoring plan is required, as provided in paragraph 7.1.1.1 of this section. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

7.2.4 The results of all required certification, recertification, and quality-assurance tests described

in paragraphs 7.1.10.3 through 7.1.10.6 of this section shall be submitted electronically, either prior to or concurrent with the relevant quarterly electronic report.

7.2.5 *Quarterly Reports.*

7.2.5.1 Beginning with the calendar quarter containing the program start date, the owner or operator of any affected unit shall submit electronic quarterly reports to the Administrator, in a format specified by the Administrator, for each affected unit (or group of units monitored at a common stack) and each non-affected unit under section 2.3 of this appendix.

7.2.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

7.2.5.3 Each electronic quarterly report shall include the following information:

7.2.5.3.1 The date of report generation;

7.2.5.3.2 Facility identification information;

7.2.5.3.3 The information in paragraphs 7.1.2 through 7.1.19 of this section, as applicable to the Hg emission measurement methodology (or methodologies) used and the units of the Hg emission standard(s); and

7.2.5.3.4 The results of all daily calibration error tests and daily flow monitor interference checks, as described in paragraphs 7.1.10.1 and 7.1.10.2 of this section.

7.2.5.4 Information which is incompatible with electronic reporting (e.g., field data sheets, lab

analyses, stratification test results, sampling equipment calibrations, quality control plan information) is excluded from electronic reporting.

7.2.5.5 *Compliance Certification.* The owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report, based on reasonable inquiry of those persons with primary responsibility for ensuring that all Hg emissions from the affected unit(s) and (if applicable) any non-affected unit(s) under section 2.3 of this appendix have been correctly and fully monitored. The compliance certification shall indicate whether the monitoring data submitted were recorded in accordance with the applicable requirements of this appendix.

[FR Doc. 2011-7237 Filed 5-2-11; 8:45 am]

BILLING CODE 6560-50-P

APPENDIX F

United States
Environmental Protection Agency

Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

EPA-453/R-98-004a
February 1998

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Study of Hazardous Air Pollutant Emissions
from Electric Utility Steam Generating Units —
Final Report to Congress

Volume 1.

[Logo]

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analysis indicate that the exposures and risks due to fish consumption are the highest of all pathways considered. The highest modeled result of 2×10^{-4} lifetime cancer risk was obtained for the subsistence fisher exposure scenario. In all modeled scenarios, the non-inhalation exposures were at least one order of magnitude larger than the inhalation exposures, thus demonstrating the potential significance of including multipathway exposure analysis in the risk assessments for pollutants that are environmentally persistent and tend to bioaccumulate. Also, unlike the results for arsenic, modeled exposures to dioxins for each pathway exceed the background exposure estimates for dioxins.

ES.10.3 Uncertainty Discussion

Several sensitivity analyses were completed for the screening level multipathway assessment of utility

dioxin risks to assess the reasonableness of the results. The assumptions with the greatest impact on the predicted risk to the subsistence fisher were those made about the biota-sediment accumulation factor. This sensitivity analysis suggests that the modeling results are reasonable for a screening level analysis.

ES.11 MULTIPATHWAY ASSESSMENT FOR RADIONUCLIDES

Radionuclide emissions from utilities may result in human exposure from multiple pathways including: (1) external radiation exposure from radionuclides suspended in air or deposited on the ground, and (2) internal exposure from the inhalation of airborne contaminants or ingestion of contaminated food. The CAP-93 model was used to estimate multipathway exposures and risks due to radionuclide emissions to humans within 50 km of all 684 utilities. However, this assessment did not use site-specific data for the non-inhalation exposure analysis, but rather relied on various generic assumptions and general input data.

Based on the CAP-93 modeling, 667 of the 684 plants are estimated to pose multipathway risks less than 1×10^{-5}. The highest estimated multipathway radiation exposure for the MEI due to radionuclide emissions from utilities was predicted to be 1.5 millirems (mRems) per year, which is estimated to pose an increased cancer risk of 3×10^{-5}. Seventeen plants (13 coal- and 4 oil-fired plants) were estimated to pose multipathway risks between 1×10^{-5} and 3×10^{-5}. The estimated cancer incidence in the U.S., due to emissions and dispersion of radionuclides within 50 km of each utility, is estimated to be 0.3 cancer deaths/yr. The cancer incidence appears to be mostly

due to inhalation exposure. The non-inhalation exposures contribute only slightly to the incidence. The non-inhalation exposure pathways have a greater impact on the MEIs, especially for coal-fired plants.

The risks due to exposure to radionuclides from utilities are substantially lower than the risks due to natural background radiation. The average exposure to natural background radiation (excluding radon) for the U.S. population has been estimated to be

* * *

ES.15.4 Potential Environmental Impacts Not Included in Study

There are other potential environmental issues associated with utilities not assessed in this report. These include: (1) the impacts of criteria pollutants (SO_2, NO_x, PM, carbon monoxide, and ozone) or acid rain precursors (SO_2 and NO_x), which are studied and regulated under other sections of the Act; (2)an assessment of ecological impacts of HAPs; (3) the impacts of carbon dioxide emissions and climate; and (4) the impacts resulting from restructuring, mining, drilling, solid waste disposal, transmission, transportation, or other activities associated with electric power generation. These issues and potential impacts were not assessed because they were considered beyond the scope of this study as mandated by Section 112(n) of the Act.

ES.15.5 Link to Particulate Matter

Arsenic, cadmium, chromium, lead, nickel, radionuclides, and several other HAPs are emitted primarily as PM. Consequently, these HAPs may contribute to PM emissions and PM health concerns, especially from poorly controlled coal-fired units and uncontrolled oil-fired units (about two-thirds of oil-

fired units are uncontrolled for PM). Impacts for PM were not addressed in this study, but are being studied under Title I of the Act. If additional controls of PM emissions are utilized, this could result in reductions in HAP emissions.

ES.16 OVERALL TECHNICAL SUMMARY AND CONCLUSIONS

Based on available information and current analyses, the EPA believes that mercury from coal-fired utilities is the HAP of greatest potential concern and merits additional research and monitoring. There are uncertainties regarding the extent of risks due to mercury exposures including those from utility emissions. Further research and evaluation are needed to gain a better understanding of the risks and impacts of utility mercury emissions. In addition, further research and evaluation of potential control technologies and strategies for mercury are needed.

For a few other HAPs, there also are still some remaining potential concerns and uncertainties that may need further study. First, the screening multipathway assessments for dioxins and arsenic suggest that these two HAPs are of potential concern (primarily from coal-fired plants); however, further evaluations and review are needed to better characterize the impacts of dioxins and arsenic emissions from utilities. Second, nickel emissions from oil-fired utilities are of potential concern, but significant uncertainties still exist with regards to the nickel forms emitted from utilities and the health effects of those various forms. The impacts due to HAP emissions from gas-fired utilities are negligible based on the results of this study; therefore, the EPA feels that there is no need for further evaluation of the risks of HAP emissions from natural gas-fired utilities.